an international monthly

THE Petroleum Engineer

Combined Edition

Drilling and Producing | Refining and Gas Processing | Oil and Gas Pipelining

HALLIBURTON MEASURING DEVICES

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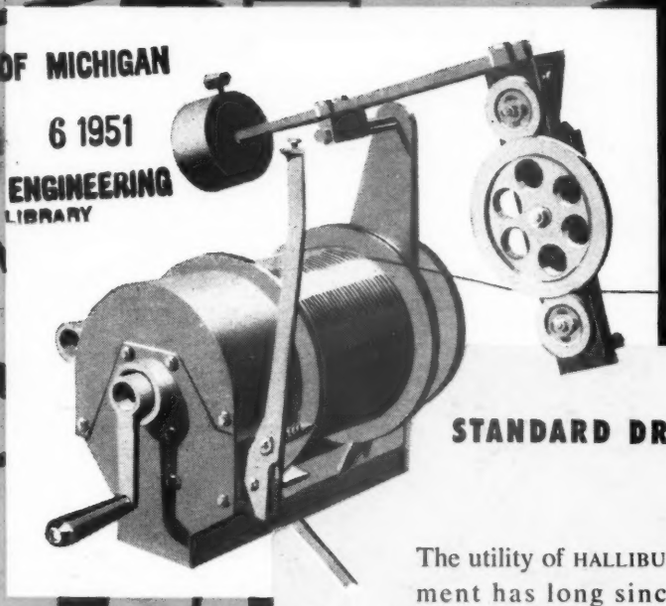

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The utility of HALLIBURTON measuring equipment has long since been expanded to hundreds of important uses other than oil well cementing. They've become a standard part of drilling equipment throughout the world. They eliminate guesswork and miscalculations because the Veeder Counter on each HALLIBURTON MEASURING DEVICE reads *exact* depths *directly*. Let your HALLIBURTON representative describe and recommend the types best suited to your problems. *Call him today!*

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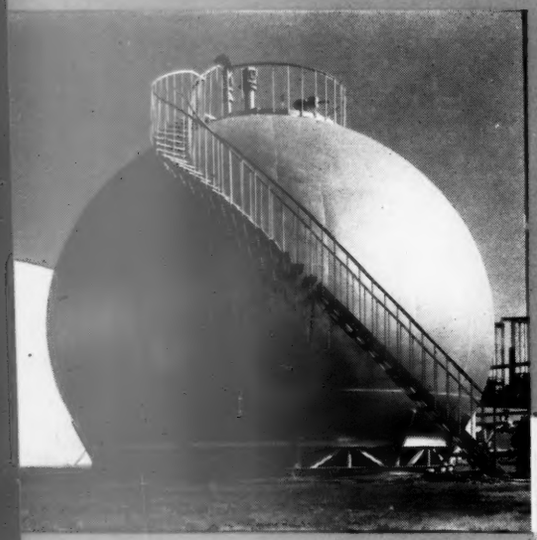
HORTON STEEL STRUCTURES

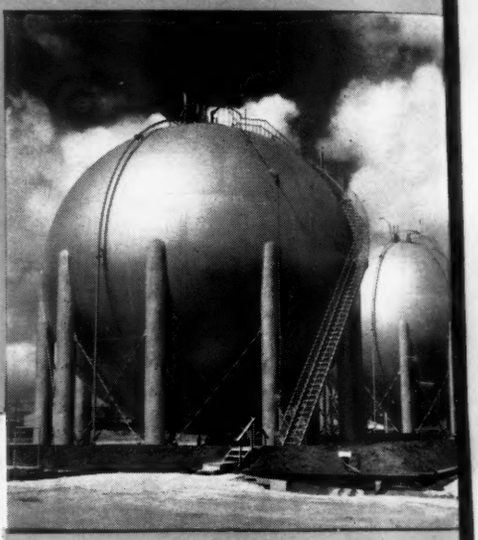
DEPENDABLE SERVICE FOR THE PETROLEUM INDUSTRY

Our engineering staff, our four fabricating plants and our experienced field crews offer the petroleum industry complete, dependable service in the expert design, fabrication and erection of oil storage tanks and special steel plate structures. The accompanying illustrations show a few examples of the types of Horton structures now in service throughout the petroleum industry. Our engineers will be glad to work with you whenever you need steel plate structures of any type.

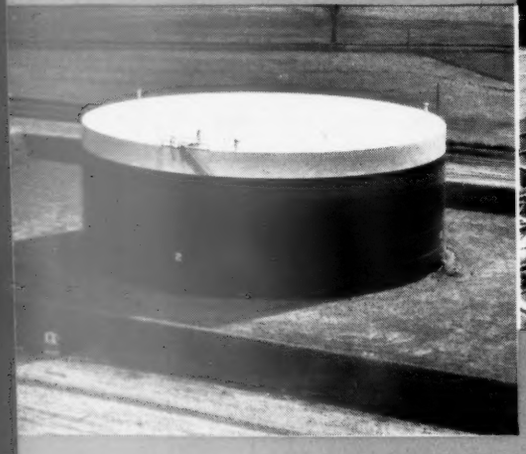
Below: HORTONSPHEROIDS... widely used in sizes up to 120,000 bbls. for the pressure storage of moderately volatile liquids such as motor gasoline and natural gasoline.

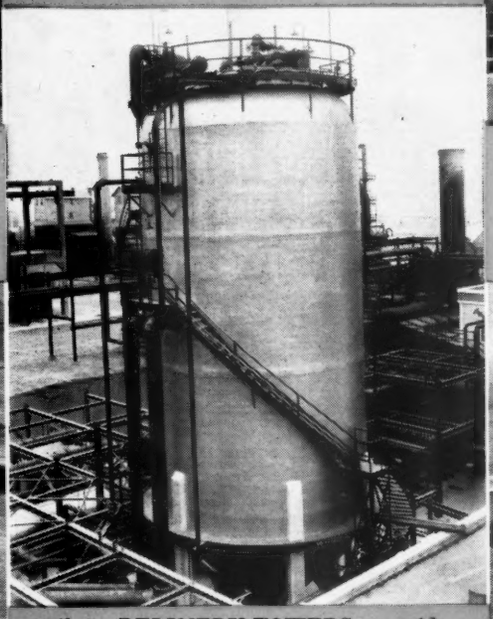


Below: HORTONSPHERES... for p sure storage of highly volatile material prevent loss, to reduce fire hazard an decrease corrosion. Sizes up to 25,000 b



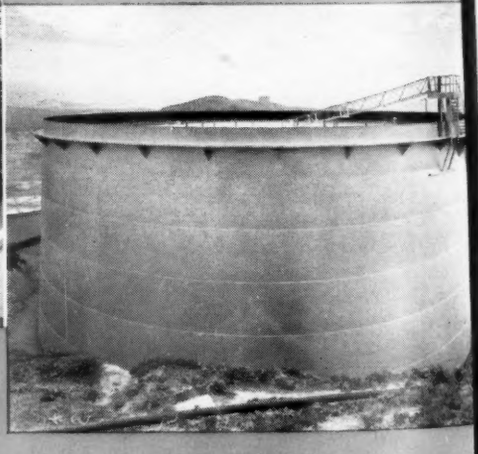
Below: FLAT-BOTTOMED TANKS... of welded steel construction, built in accordance with API specifications, in standard sizes from 500 to 150,000 bbls.





Above: REFINERY TOWERS... wide range of towers and pressure vessels, built in accordance with API-ASME specifications or the ASME code for Unfired Pressure Vessels.

Below: HORTON FLOATING ROOFS.. available in three types, for tanks fill and emptied frequently, in blending se vice, or storing corrosive products.



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EDITORIAL

THE oil industry is keenly conscious of its many operating problems, and is doing something about it. Evidence of this is the phenomenal growth in recent years of research groups within the industry. Down-to-earth problems encountered in field and plant are now coming in for detailed study. Research programs for the most part are planned with a view to reducing costs, seeking new methods, and improving the efficiency of operations in general. In the drilling branch of the industry, improved mechanical equipment and methods are under constant development. To meet the challenge of deep drilling, revolutionary changes are foreseen.

Keeping old wells on production as long as possible, ways to increase their economic life and leave as little oil as possible in the reservoir are tied in with developments in secondary recovery. The pace of progress in the last two years in secondary recovery practice has been encouraging. Old and new fields are being studied and efforts made to cut down the underground waste that might result from improper methods of developing a field.

In the refining and gas processing industry new processes are constantly being developed to increase and improve yields and products. The more fundamental operating phases of plant operation are not being overlooked. Problems of corrosion, plant performance, and water treating are coming in for an increasing share of study. Each is vital in maintaining and improving the efficiency of plant operation.

The network of oil and gas pipelines has undergone vast expansion in recent years. Great progress has been made in the laying, equipping, and operating of pipelines. Evidence of this progress was the technical conference held in Atlanta, Georgia, recently, in which the technical phases of design, construction, and operation came in for scrutiny and discussion.

As might be expected, the literature reflects these increasing activities of the industry. This issue is devoted to papers of high reference value, specially selected for our readers. They are but a percentage of the valuable papers presented during the year before industry associations. They are, however, of current interest and a valuable aid in keeping abreast of developments in the industry. The bibliography published each month is a supplementary reading list of current additions to the literature, the most complete reference collection of its kind.

15 TYPICAL APPLICATIONS for

FLUOR FIN-FAN AIR-COOLED Heat Exchangers

	SERVICE	HEAT TRANSFER (BTU/HR.)	TOTAL H.P.	GROUND SPACE
GAS COOLING	Natural Gas After-Cooler	13,920,000	80	46′ x 25′
	Manufactured Gas Cooler	11,165,000	50	23′ x 21′
	Natural Gas After-Cooler	3,400,000	15	11′ x 21′
	Natural Gas Inter-Cooler	7,890,000	40	23′ x 21′
VAPOR CONDENSING	Reflux Condenser	18,407,000	90	48′ x 25′
	Primary Condenser	4,652,000	40	11′ x 25′
	Still O.H. Condenser	4,875,000	34	16′ x 21′
	Debutanizer Condenser	11,930,000	60	23′ x 25′
	Still Reflux Condenser	39,110,000	60	46′ x 25′
	Steam Condenser	87,300,000	300	138′ x 31′
	Steam Condenser	2,880,000	10	10′ x 6′
LIQUID COOLING	Vegetable Oil Cooler	628,000	15	6′ x 17′
	Absorption Oil Cooler	14,915,000	100	32′ x 17′
	Quenching Oil Cooler	1,665,000	50	23′ x 25′
	Amine Solution Cooler	19,300,000	175	38′ x 25′
	Stabilized Crude Cooler	125,100,000	700	315′ x 25′
	Jacket Water	2,400,000	5.5	16′ x 12′
	Jacket Water	28,800,000	100	70′ x 24′

A new 8-page bulletin on Fluor-GR Fin-Fan Heat Exchangers is now being prepared. Write in and reserve your copy by post card or letter.

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The Fin-Fan Air-Cooled Heat Exchanger is unique in its development and manufacture. It is the result of the engineering skill of *two* companies, *each* long recognized as leaders in their respective fields. It combines Fluor's experience in the design, fabrication and field erection of air-moving systems with Griscom-Russell's experience in heat transfer.

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DATA ON IMPORTANT OIL FIELDS OF THE UNITED STATES

No.	Annual production (thousands of barrels)						Cumulative production thru 1947 (M bbl)	Estimated recovery per acre (bbl)	Number wells producing		
	1942	1943	1944	1945	1946	1947			Total	Flowing	Pumping
							LOUISIANA(Cont.)				
13	579	668	580	494	456	576	13,405	1,604	—	—	—
14	1,348	978	838	722	614	629	5,546	1,684	—	—	—
15	3,207	3,461	3,373	3,107	2,721	2,721	19,605	2,852	—	—	—
16	4,520	3,742	3,275	2,857	2,433	2,222	24,321	2,893	—	—	—
17	27	21	18	15	14	17	1,734	3,434	23	0	23
18	4,120	3,474	2,995	2,516	1,991	1,717	89,968	6,141	—	—	—
19	844	614	445	370	384	456	5,583	1,554	—	—	—
20	391	454	355	288	259	219	3,063	2,709	11	3	8
21	771	738	685	628	606	640	30,045	11,762	—	—	—
2	271	184	142	123	150	84	16,898	2,756	21	0	21
		South									
23	2,252	2,248	2,661	2,483	2,447	2,425	17,248	23,161	—	—	—
24	23	180	583	931	1,234	1,595	4,546	12,296	—	—	—
25	323	213	185	207	202	167	4,090	5,231	11	3	8
26	1,059	1,127	1,142	1,367	1,503	1,340	9,009	25,563	—	—	—
27	339	343	348	436	661	735	3,548	17,581	4	4	0
28	754	794	676	693	673	619	5,101	7,003	31	27	4
29	266	169	130	128	113	186	4,605	18,413	12	9	4
30	945	1,912	3,112	2,903	3,487	4,444	16,937	4,880	—	—	—
31	924	1,100	1,017	693	683	916	14,049	17,511	26	18	8
32	1,378	1,095	1,046	1,002	1,073	945	28,492	17,217	—	—	—
33	1,525	1,834	1,934	1,918	2,060	2,674	43,740	45,629	—	—	—
34	681	637	479	392	331	265	11,247	31,377	21	6	15
35	618	937	940	753	678	594	5,875	9,430	25	25	0
36	1,510	1,498	1,248	1,042	764	700	9,623	4,374	20	19	1
37	1,380	1,117	1,043	1,049	1,199	1,555	15,770	14,963	—	—	—
38	870	824	751	431	248	298	6,218	9,250	19	2	17
39	1,798	1,740	1,624	1,649	1,525	1,518	14,644	15,087	—	—	—
40	521	447	466	423	262	174	7,262	40,503	6	2	4
41	316	1,019	2,229	3,275	4,609	5,585	17,211	3,633	—	—	—
42	252	441	391	481	1,547	690	6,253	22,252	15	10	5
43	92	57	35	72	116	119	9,297	76,483	11	6	5
44	3,314	3,133	3,161	2,465	1,702	1,339	23,713	10,654	—	—	—
45	197	228	4,184	6,549	6,626	6,551	24,399	8,113	—	—	—
46	1,258	1,356	1,256	1,140	1,167	1,285	12,188	19,128	—	—	—
47	1,052	1,700	2,106	1,909	1,315	903	14,198	17,966	—	—	—
48	275	841	1,433	1,470	1,270	1,150	6,464	9,489	—	—	—
49	850	490	305	218	186	171	23,422	19,376	11	5	6
50	4,445	3,559	2,796	2,504	2,399	2,684	28,086	14,112	149	45	104
51	1,996	2,511	2,704	3,011	3,094	3,411	20,526	12,678	56	56	0
52	1,168	954	845	734	670	648	8,226	12,630	20	20	0
53	883	1,248	1,681	1,672	1,677	1,552	10,468	18,575	—	—	—
54	1,502	1,826	1,765	1,642	1,669	1,695	38,478	22,989	—	—	—
55	1,828	1,957	2,342	2,157	2,140	2,340	20,705	21,863	—	—	—
56	304	455	402	435	419	678	4,155	5,795	10	10	0
57	2,296	2,610	2,613	2,156	1,743	1,524	37,622	120,327	—	—	—
58	2,507	2,929	3,307	2,726	2,515	2,434	62,657	57,907	—	—	—
59	669	617	475	360	270	321	12,384	31,745	17	10	7
60	4,408	3,437	2,871	2,434	2,034	1,820	98,299	120,599	—	—	—
61	3,747	4,685	4,448	4,186	4,781	4,356	53,463	16,369	—	—	—
62	184	161	158	143	176	133	18,439	36,612	16	1	15
63	618	826	727	680	511	562	5,750	5,188	9	7	2
64	235	401	641	918	1,297	1,433	8,338	18,171	—	—	—
65	720	990	1,567	1,611	1,637	1,602	8,784	7,182	—	—	—
66	139	146	150	176	174	190	4,040	19,250	7	7	0
67	1,013	1,254	1,427	1,564	1,401	1,559	31,348	24,824	—	—	—
68	261	257	243	279	319	292	17,173	23,446	20	9	11
69	891	1,344	2,345	2,296	1,725	1,173	10,939	2,511	—	—	—
70	1,798	1,705	1,624	1,646	1,525	1,521	14,647	15,087	42	36	6
71	2,249	4,172	4,014	3,652	3,845	3,737	22,922	3,837	—	—	—
72	875	1,424	1,952	1,943	1,715	1,549	9,711	5,441	53	40	13
73	951	1,231	1,219	1,040	1,102	1,370	16,763	24,241	—	—	—
74	607	695	595	472	454	428	4,302	13,836	17	9	8
75	2,098	2,556	2,860	2,963	3,209	3,386	22,124	9,096	—	—	—
76	599	771	730	598	563	532	5,569	8,995	13	12	1
77	611	602	766	837	833	790	13,581	9,405	—	—	—
78	1,347	1,733	1,954	1,915	1,741	1,688	10,914	7,208	—	—	—
79	176	196	198	148	188	95	4,304	16,188	21	1	20

(Continued)

From The Petroleum Data Book, Second Edition, which carries 750 pages of information on the petroleum industry.

DATA ON IMPORTANT OIL FIELDS OF THE UNITED STATES

No.	Year discovered	Field	County	Producing formation	Gravity °API	Productive acres	Estimated Average thickness (feet)
				LOUISIANA (Cont.)			
13	1936	Lisbon	Lincoln, Claiborne	Sligo, Hosston, Smackover, Cotton Valley	33; 42; 56	8,000	30
14	1941	Little Creek	La Salle	Wilcox	31.0	2,920	—
15	1940	Nebo	La Salle	Wilcox, Cockfield; Eoc	40.0	5,920	400
16	1940	Olla	La Salle	Wilcox	31.0	7,640	—
17	1927	Pleasant Hill	Sabine	Paluxy	40.0	500	10
18	1935	Rodessa	Caddo	Rodessa Li, Young, Hill, Loyd, Glees, Mitchell	44.0	14,370	20
19	1933	Sligo	Bossier	Nacatoch, Ozan, Tokio, Paluxy, Morningsport, Rodessa, Sligo, Hosston	41.0	3,300	25
20	1937	Sugar Creek	Claiborne	Rodessa, Sligo, Hosston	35.0	1,050	15
21	1925	Urania-Tullos-Georgetown	Winn, La Salle, Grant	Wilcox, Eoc	18.0	2,500	10
22	1928	Zwolle	Sabine	Annona	40.0	6,100	—
		South					
23	1902	Anse La Butte	St. Martin	Mio, Olig	23.0-40.0	640	65
24	1942	Avery Island	Iberia	Mio	32.0-47.0	240	50
25	1938	Bancroft	Beauregard	Cockfield; Eoc	46.7	750	15
26	1939	Barataria	Jefferson	Mio	33.4-47.0	300	50
27	1937	Bateman Lake	St. Mary	Mio	33.0-45.0	160	50
28	1929	Bayou Blue	Iberville	Mio	17.1-38.0	640	20
29	1931	Bayou Choctaw	Iberville	Mio	26.0-37.0	240	20
30	1941	Bayou Sale	St. Mary	Mio	38.0	2,560	35
31	1929	Black Bayou	Cameron	Mio U, Mio L, Frio	22.0-65.0	750	400
32	1934	Bosco	St. Landry, Acadia	Mio L	38.0-48.0	1,600	16
33	1930	Caillou Island	Terrebonne	Mio U (14 pays in Mio)	35.0-40.0	900	100
34	1931	Cameron Meadows	Cameron	Pli, Mio	20; 28.-42.	350	30
35	1938	Chacahoula	Lafourche	Mio	34.0	560	30
36	1938	Chalkley	Cameron	Mio, Olig	36.0	2,040	35
37	1936	Charenton	St. Mary	Pli, Mio	37.0	950	20
38	1935	Cheneyville	Rapides	Cockfield, Sparta	44.0	640	20
39	1937	Crowley, North	Acadia	Mio	37.0	870	25
40	1932	Darrow	Ascension	Mio U, Mio L	30.0; 39.0	175	27
41	1940	Delta Farms	Lafourche	Mio	35.0	3,200	40
42	1929	Dog Lake	Terrebonne	Mio	33.0-52.0	250	60
43	1912	Edgerly	Calcasieu	Mio U, Olig	22.0; 40.8	120	20
44	1939	Eola	Avoyelles	Cockfield, Sparta, Wilcox	36.0-48.0	2,100	35
45	1940	Erath	Vermilion	Mio	31.0-51.0	2,200	35
46	1935	Garden Island Bay	Plaquemines	(11 pays in Mio)	35.0	570	400
47	1937	G bson	Terrebonne	(9 pays in Mio)	37.0	740	100
48	1941	Gibson, N. E.	Terrebonne	Mio	37.0	560	100
49	1934	Gillis English Bayou	Calcasieu	Mio U, Mio L	31.0-36.0	1,200	90
50	1938	Golden Meadows	Lafourche	Mio	36.0	1,800	40
51	1938	Grand Bay	Plaquemines	(8 pays in Mio)	31.0-39.0	1,350	100
52	1939	Grand Lake	Cameron	Mio	32.5	600	35
53	1932	Gueydan	Vermilion	Mio	30.0; 60.0	480	25
54	1927	Hackberry, East	Cameron	Mio U, Mio L, Olig	27.0; 33.0-51.0	1,600	125
55	1928	Hackberry, West	Cameron	Mio U, Mio L, Olig	21.0-31.0	840	75
56	1937	Horseshoe Bayou	St. Mary	Mio	38.0-46.0	600	60
57	1917	Iberia	Iberia	Pli, Mio U	18.0-24.0	300	100
58	1931	Iowa	Jefferson Davis, Calcasieu	Mio U, Mio L	30.0; 36.0-58.0	1,040	75
59	1935	Jeanerette	St. Mary	Mio	35.0	380	45
60	1901	Jennings	Acadia	Mio U, Pli	25.0-38.0	800	250
61	1935	Lafitte	Jefferson	Mio, Olig	37.0	3,000	25
62	1929	Lake Barre	Terrebonne	Mio U, Frio	30.0	500	80
63	1937	Lake Long	Lafourche	Mio	36.0-51.0	1,000	30
64	1929	Lake Pelto	Terrebonne	Pli, Mio	34.0-43.0	380	40
65	1940	Lake Salvador	St. Charles	Mio	34.0	1,000	25
66	1931	Lake Washington	Plaquemines	Cap Rock	18.0	200	—
67	1931	Leeville	Lafourche	Mio	32.5	1,200	40
68	1924	Lockport	Calcasieu	Pli, Mio U, Mio L	23.0-47.0	720	100
69	1940	Neale	Beauregard	Wilcox	45.0	3,890	70
70	1937	North Crowley	Acadia	Mio U, Mio L	37.0	870	35
71	1939	Paradis	St. Charles	(300 ft sand Mio)	37.0	5,000	300
72	1912, 41	Pine Prairie	Evangeline	Cockfield, Sparta, Wilcox	38.0-47.0	1,500	50
73	1929	Port Barre	St. Landry	Mio U, Mio L, Olig	21.0-60.0	635	160
74	1937	Potash	Plaquemines	Mio	28.0	280	205
75	1937	Quarantine Bay	Plaquemines	(10 pays in Mio)	30.0	2,060	220
76	1938	Raceland	Lafourche	Mio	36.0	560	25
77	1934	Roanoke	Jefferson Davis	Mio L	39.0; 57.0	1,360	30
78	1941	St. Gabriel	Iberville	Mio, Olig	33.0	1,280	25
79	1927	Starks	Calcasieu	Pli, Mio	18.0-55.0	260	75

*Includes Blue Lake.

From The Petroleum Data Book, Second Edition, which carries 750 pages of information on the petroleum industry.

UNITED STATES OIL WELLS DRILLED, ABANDONED, AND PRODUCING AT END OF YEAR

Year	Producing oil wells drilled	Oil wells drilled, cumulative	Oil wells shut in or abandoned	Oil wells shut in or abandoned, cumulative	Total producing oil wells on December 31
1900	13,671	140,907	4,599	62,162	78,745*
1901	11,811	152,718	5,445	67,607	85,111*
1902	13,019	165,737	5,759	73,366	92,371*
1903	15,177	180,914	6,366	79,732	101,182*
1904	16,008	196,922	6,262	85,994	110,928*
1905	12,601	209,523	7,586	93,580	115,943*
1906	14,550	224,073	7,903	101,483	122,590*
1907	15,534	239,607	5,084	106,567	133,040*
1908	13,215	252,822	4,802	111,369	141,453*
1909	13,906	266,728	8,623	119,992	146,736*
1910	11,025	277,753	9,142	129,134	148,619*
1911	9,828	287,581	7,654	136,788	150,793*
1912	12,518	300,099	8,265	145,053	155,046*
1913	19,099	319,198	3,371	148,424	170,774*
1914	16,669	335,867	7,266	155,690	180,177*
1915	9,155	345,022	8,015	163,705	181,317*
1916	18,844	363,866	8,053	171,758	192,108*
1917	16,636	380,502	9,425	181,183	199,319*
1918	17,860	398,362	9,364	190,547	207,815*
1919	21,041	419,403	772	191,319	228,084*
1920	24,273	443,676	—15,890	175,429	268,247
1921	14,666	458,342	8,413	183,842	274,500
1922	17,333	475,675	6,953	190,795	284,880
1923	16,206	491,881	10,986	201,781	290,100
1924	14,587	506,468	5,587	207,368	299,100
1925	16,559	523,027	9,559	216,927	306,100
1926	19,013	542,040	6,513	223,440	318,600
1927	14,442	556,482	9,742	233,182	323,300
1928	12,526	569,008	8,026	241,208	327,800
1929	15,572	584,580	15,172	256,380	328,200
1930	11,640	596,220	8,770	265,150	331,070
1931	6,788	603,008	22,008	287,158	315,850
1932	10,444	613,452	4,794	291,952	321,500
1933	8,068	621,520	2,718	294,670	326,850
1934	12,512	634,032	6,292	300,962	333,070
1935	15,108	649,140	7,188	308,150	340,990
1936	17,800	666,940	9,340	317,490	349,450
1937	22,143	689,083	8,563	326,053	363,030
1938	19,121	708,204	12,511	338,564	369,640
1939	17,485	725,689	6,735	345,299	380,390
1940	19,125	744,814	10,505	355,804	389,010
1941	19,195	764,009	8,245	364,049	399,960
1942	10,524	774,533	5,644	369,693	404,840
1943	9,717	784,250	7,387	377,080	407,170
1944	13,029	797,279	7,979	385,059	412,220
1945	14,297	811,576	10,767	395,826	415,750
1946†	15,810	827,386	10,100	405,926	421,460
1947†	18,037	845,423	10,161	416,087	429,336

*W. P. A. National Research Project E-10-1939.

†*The Petroleum Data Book* Research Department.

Source: U. S. Bureau of Mines; Independent Petroleum Association of America.

From The Petroleum Data Book, Second Edition, which carries 750 pages of information on the petroleum industry.

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The HISTORIAN Looks at OIL †

The Age of the Muckraker has passed but the public has been left with the sensational accounts of early outlawry in lieu of a real objective picture of the oil industry—the onus of watered stock, monopoly, and oil "scandals" are remembered and written about while the valuable contributions of the industry are scarcely mentioned in the history of our times

CARL COKE RISTER*

THE era of the late 1890's and the early 1900's was characterized by the rise of monopolies, giant corporations, and trusts. In the six years from 1898 to 1904, indeed, 236 American industrial trusts were organized with an aggregate capitalization of six billion dollars, with approximately half that amount in watered stock. And these enterprises were often led by "malefactors of great wealth" or "robber barons," as their critics called them, who had cut their industrial teeth on the hard rock of ruthless competition, upon which the barks of less fortunate operators had been wrecked. In business, they employed "catch-as-catch-can" ethics and cutthroat competition, and acknowledged no legal restraint. Consequently, they were the bane of honest business or industrial organizations and the enemies of independent enterprises.

The courts of our land charged with enforcing the Interstate Commerce Act (1887) and the Sherman Anti-Trust Act (1890) could hardly cope with these industrial outlaws and their organizations, for ordinarily, corporation lawyers were the best in the land. They were skilled at circumventing the law by legal dodges and delays and were often far better trained and experienced in corporation law than poorly paid federal attorneys. During the administration of President Benjamin Harrison only five prosecutions were begun under the Sherman law, and of these 4 failed; and while Cleveland was president 18 cases were prosecuted under the Sherman Act, 7 of which involved combinations of labor. Of the 11 other cases against corporations, only one was successfully prosecuted. Such a record must have hastened the formation of other powerful concerns, for in the decade following the passage of the Sherman Act more than 100 industrial combinations were formed, with a combined capital of more than $3,000,000,000.

This was also an era when private, industrial, and public morals sadly needed strengthening. The life-savings of thousands of people were squandered by the watering of corporation stock; western farmers often

†Presented before Texas Mid-Continent Oil and Gas Association, 31st annual meeting, Dallas, Texas, October 5, 1950.

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suffered because of arbitrary, excessive freight rates; small business enterprises were ruthlessly snuffed out by avaricious trusts; the prices of both raw materials and finished products rose or fell at the command of monopolists; and an American economy favoring the survival of the fittest at the expense of the many was in the making.

The Muckrakers

But industrial outlaws had not reckoned with public opinion, which was rapidly crystallizing against them, of which the sensational rise of the Farmers' Alliance and the Populist movement, and the growth of the Labor Party and Bryanism were symptomatic. Keen-witted journalists and literati saw the rise of this general anti-monopolist movement, however, and made capital of it, for coming from their pens were such devestating exposes as Lincoln Steffens' *Shame of the Cities*, Thomas W. Lawson's *Frenzied Finance*, Upton Sinclair's *The Jungle*, and Ida M. Tarbell's *History of the Standard Oil Company*. And muckraking editors of *McClure's*, *Cosmopolitan*, and *Munsey's* and other magazines lent their columns to sensational stories about foul stockyards, packing-plants, food manufacturers, unsightly factories, corrupt political deals, stock-gambling, and the mismanagement of finance.

Thus, this era also had its industrial reformers, or the "muckrakers" as Theodore Roosevelt called them. Yet Roosevelt was the first politician to seize upon and make capital of their exposes by noisily declaring war on dishonest trusts. By so doing he shocked the American spirit out of its complacency and inadvertently launched a movement of judicial, administrative and legislative reform that by the time of Woodrow Wilson's administration had met with considerable success.

Of all these muckraking writers, perhaps the name of Ida M. Tarbell is best known to oilmen. Earlier, Miss Tarbell's family had lived in Oil Creek, Pennsylvania, and had sought to maintain its Puritan standards during the periods of riotous lawlessness in that oil country. Then, when opportunity beckoned, the family moved to Titusville, where the family fortunes were severely affected, or so they thought, by the rise of the Standard Oil Company. Although Miss Tarbell later denied that her father's misfortune had in any way imbittered her against Rockefeller and his trust, it evidently did so, for her *History of the Standard Oil Company* is conspicuously subjective.

Miss Tarbell spent 4 years in studying numerous records before she wrote her book. She examined dozens of reports of suits in which the Standard Oil Company had been involved, newspaper files, congressional hearings, and a wide variety of other materials. Then she wrote her complicated story of the rise, practices, and success of the Standard Oil Company under the guiding genius of John D. Rockefeller.

And unintentionally perhaps, Miss Tarbell also included in her narrative a brief history of the American oil industry during a period when oil wells were but little deeper than water wells, when storage and transportation facilities were primitive, when the demand for crude oil was narrowly limited to lamp, lubrication, and medicinal uses, and when refineries were little more than skimming vats.

This period of oil history was transitional. In 1854 George H. Bissell, a graduate of Dartmouth College, had acquired western Pennsylvania leases and had sought to create interest in petroleum by submitting a sample of that region's crude oil to Benjamin Silliman, Professor of Chemistry at Yale College. Although "Seneca Oil," "American Medical Oil" and other preparations were sold both in America and Europe, the consumption of crude oil for medicine and other purposes was relatively small. Silliman's analysis, however, revealed that oil made an excellent alluminant and contained such useful by-products as naphtha and paraffin. Silliman's findings created a lively interest and led to the rapid development of the Pennsylvania oil region. Wells were sunk, and the railroads began building into the oil country. Lamp oil presently supplanted whale oil and candles then used for lighting homes. In 1864 Samuel Van Syckel opened the first pipe line with relay filling stations, and by 1872 the cumulative crude oil production had climbed to almost 40,000,000 bbl. Present-day oilmen would regard this as a small output but it should be remembered that the oil industry was then in its infancy.

The Rockefeller Story

It was about this time, in Miss Tarbell's narrative, that John D. Rockefeller appeared in the oil country. Another writer, C. C. Regier[1] says of him: "He was quiet, thoughtful, industrious, taciturn, and not unduly troubled by ethical considerations. Already aiming at a monopoly, he saw that the first step was to secure control in Cleveland. To do this it was necessary to get secret rebates from the railroads, a task which was simplified by the fact that the railroads were weary of the rate wars and were willing to accept any scheme that would stabilize freight rates, even though that scheme might be dishonest and criminal. As a result, the South Improvement Company received not only rebates for its own freight but also for the freight shipped by competitors. That is, if any independent concern paid 80 cents a barrel for shipping its oil, 40 cents of that amount went to the Rockefeller company. Moreover, the company had complete access to the books of the railroads, and could know the destination of every barrel of oil sent out of Cleveland."

Miss Tarbell wrote much the same thing. She charged the Standard Oil Company with every form of unfair practice—of snuffing out small refinery enterprises by cut-throat competition, of so dominating railroads crossing the oil country that they were forced to open their books to the inspection of Standard Oil agents, of vicious underselling practices, and of controlling the markets of both refined and crude oil. She asserted, too, that if competing refiners for a time survived such ruthless competition, they at last were "frozen out" and the Standard Oil Company took over all the business.

Throughout the nation the reception of Miss Tarbell's narrative was both favorable and unfavorable. For example, a reviewer of the *Arena* praised it as "a fearless unmasking of moral criminality masquerading under the robes of respectability and Christianity." But in his book, *The Raid on Prosperity* (New York, 1907), James Roscoe Day of Syracuse University disagreed. He defended the Standard Oil Company, claiming that it was a boon to the working man and a civilizing force in the nation. Rockefeller, too, in 1908 and 1909, offered a mild rebuttal by publishing in *World's Work* his "Random Reminiscences," maintaining that his company had been misunderstood and that it had promoted the prosperity of the oil country. He generously gave credit to his associates for its phenomenal success.

Nevertheless, public opinion during the years to follow indicated a positive acceptance of Miss Tarbell's exposé and indeed applied it to other oil company executives, as surprising as that may seem. There was no definitive history of the industry, for no historian of national repute had seen fit to enter this field of research. And for the study of American history in colleges and high schools of the nation, textbooks were used that either made no mention of the oil industry and its contribution to industrial life or they dismissed the subject as of

[1] *The Era of the Muckrakers* (Chapel Hill, 1932), 123-4.

little importance. Yet teachers listed the subject for collateral reading, but invariably gave as a reference Miss Tarbell's *History of the Standard Oil Company*. In the decades to follow, therefore, this book was about the only one which related to the oil industry that high school and college students read. It is not surprising, therefore, that they developed an adverse opinion toward John D. Rockefeller and the Standard Oil Company in particular and oil company executives and the oil industry in general.

Bad Publicity Continues

American history textbook writers also helped to promote this false conception, although most of them had been rigorously trained in sound research methods and objective writing. Since they themselves had not delved into original records (and perhaps just here oil companies were in large part to blame, for they would not permit researchers the use of their records), and since Miss Tarbell's book was the only source of information on oil generally known over the nation, they gleaned largely from her findings in mentioning the oil industry in their textbooks.

In my opinion all these factors tended to create an unfriendly climate for the modern oil industry. Is it not significant in congressional and legislative debate relating to the oil industry that generally the overtone is combative and unfriendly? Demagogues are often prone to hold up oil companies as guilty of exploiting our national resources and of flagrant mal-practices, and both the federal Congress and state investigative committees consider unfriendly legislation again and again, and have unceremoniously hauled oil company officials before them. Examples of this nature are too common to doubt this propensity of our law makers.

Since its early Pennsylvania years science and technology have brought to the oil industry amazing intricacies and streamlined efficiency. And under its highly competitive and free enterprise system, more than 1,360,000 wells have been drilled since 1859 and 37 billion barrels of crude oil have been taken from oil horizons, with our proved reserves increasing decade after decade.

Throughout the last 48 years the oil industry has been the Gulf Southwest's most stabilizing enterprise, revealing its frontier nature in every stage of its development, with scientific techniques bringing revolutionary and novel changes. In his search for oil the prospector has exchanged soothsaying and the divining rod for the seismograph, the magnetometer, the gravity meter, and torsion balance to set sound waves in motion upward through various rock strata, to reach deeply buried bumps or arches of magnetic rocks, or to measure minute differences in the pull of gravity to ferret out heavy rock domes or salt domes—all to find clues to oil traps thousands of feet deep. Drillers have abandoned the spring pole and wooden derrick in favor of rotary equipment and giant steel derricks, some of which are capable of holding up more than 1,000,000 lb of drill pipe or casing and of sending their bits into formations four miles deep.

Chemists and physicists have also advanced the sciences of gas and oil-hydrocarbon refining and manufacturing, performing in their laboratories many "miracles from molecules" and making possible more than 1200 useful products. They have also developed the present-day refineries, awesome cities of steel, with their roaring furnaces generating hundreds of degrees of heat, with assemblages of huge catalytic crackers, stills, fractionating towers, mazes of large and small pipes, and with vast farms of storage tanks, like monster toadstools. These mechanical innovations have made modern refineries little like the primitive "skimming vats" and "tea kettles" of a few decades past.

And as to its transforming economic influence, the Gulf Southwest's petroleum industry stands out conspicuously in comparison with other western industries. The value of its cumulative crude oil yield from 1901 to 1945 has been approximately four times that of both gold and silver produced in 12 leading mineral-bearing western states, and, in 5 of these states during the decade 1936-1946, almost a third more than the combined income from their cotton, corn, and wheat. In the last year of this decade Texas petroleum and petroleum products brought nearly $150,000,000 more than this state's combined income from farm crops and livestock and products (including government subsidies). The cattle industry, too, suffers in comparison. The cumulative wealth from the Great Plains cattle industry of the last 50 years is dwarfed beside the oil income of the Gulf Southwest during this period.

The oil industry's impacts on the Texas citizen and his institutions have been equally marked, as may be seen in figures relating to this state, which produces two-thirds of the Gulf Southwest's oil. In Texas during 1947 alone the oil industry's payments in wages and salaries, lease rentals, bonuses and royalty, for equipment and supplies, for contract drilling, for geophysical prospecting, in state and local taxes, in interest on borrowed money, and for other investments, amounted to $2,253,181,000. And in other Gulf Southwest states its expenditures were proportionately as great.

In the light of these facts, and numerous others could be cited, it seems just as illogical to think of the modern oil industry as being much that of its "lamp and lubrication" years as it does to identify present-day transportation with its prairie schooner and horse and buggy years. It should be said, too, that public, business and professional ethics have steadily improved since the muckraking era. If oilmen of the late nineteenth and early twentieth centuries engaged in sharp dealings, they were certainly no worse than other industrial leaders of that period. All were products of their time; some were circumspect, others were not. American people have a

Marshall Plan Aid to Europe Praised

The Marshall Plan was given credit for the fact that Europe is making some progress toward economic recovery in a paper presented before the Third World Petroleum Congress at The Hague, by E. Groen, secretary of the Netherlands Government office for petroleum, and delegate to the Organization for Europe Economic Cooperation Oil Committee.

In his paper entitled, "The Significance of the Marshall Plan for the Petroleum Industry in Europe," Groen pointed out that world production of crude oil has soared far greater than could be expected at the beginning of the Marshall period, and lack of refining capacity, has, in the general opinion, since been overcome. Groen added that great activity is taking place in the realm of transport, as witness the substantial expansion of the world tanker fleet.

He stressed the fact that petroleum is playing a more and more important role in the economy of the OEEC countries, and that the refinery expansion program has developed to the point that 1950's output was 150 per cent above that of the 1947 level. He concluded that Europe is being equipped with refineries that operate efficiently, and that will undoubtedly make a valuable contribution to the recovery of the European economy.

tendency to make hasty generalizations in such matters. Certainly, the average oilman of today is as progressive a citizen as any other industrialist and he has made a contribution to the American economy of which we may well feel proud.

But how does the present-day historian look at oil, you may ask? I shall give you the answer to this question by listing the results of my recent study of 13 leading university and college textbooks in American history. The indexes of three of them do not even include the word "oil" or "petroleum," and in 6 of them the petroleum industry is not discussed, except in four instances where it is presented in connection with "oil scandals." One text, indeed, devotes 13 pages to "oil scandals," six others from three to almost 5 pages, and the average of all thirteen, 3.3 pages.

In those textbooks that include a presentation of the oil industry, the space devoted to the subject runs from two or three lines to 5½ pages, while that to oil scandals from one-half to 13 pages. The average space in all 13 textbooks devoted to the rise and development of the oil industry is one page, while gold discovery and mining is given more than four times as much space. W. Jett Lauck says that all the gold and silver produced in the world from 1493 to 1875 was worth but fifteen and one-third billion dollars.[2] Yet the United States crude oil output since 1859, at posted field prices, has been worth approximately 4 times that amount, which would seem to justify reversing the textbook space given to these two natural resources.

It is also apparent that the American historian is far less familiar with the rise and development of the oil industry than he is with mining, lumbering, coal-mining, steel manufacture, the automotive industry, or agriculture. His textbook coverage of the oil industry is generally that of its beginning, e.g. the Drake well, early Pennsylvania oil history, and the rise of the Standard Oil Company. Indeed, one account of about 9 pages traces the early industry's development and the Standard Oil Company by prefixing it with a scathing arraignment of the early-day and modern oilman;[3] and another softens its condemnation of Rockefeller with, "Yet it is only fair to say that his competitors were no less unscrupulous than himself."[4] Still another says that the Standard Oil trust was accomplished only on paper, that today the inevitable integration of capital has often created a community of interest that has produced a situation similar to monopoly.

I might also add that the oil industry fares no better in one or two-volume editions of parallel readings, nor in state histories of even the oil states. May I suggest that fathers present examine your children's American or state history textbooks. No doubt you will find much the same treatment of the oil industry as I have found. Now I do not know how many high school and college students are studying American history annually, but from incomplete figures available I would estimate them roughly at 3,500,000. One may well see how over a decade this would become a goodly percentage of our future citizens.

Now what is the net result of these unfortunate incidents and circumstances of the past? Do they constitute a modern problem for the oil industry? If so, what can be done about it?

If annually 3,500,000 high school and college students enrolled in general United States history courses have the opportunity of reading about the oil industry, within a decade 35,000,000 these future citizens will have had this same opportunity. At best, as stated, these history texts picture the oil industry inadequately, in connection with scandals, or in an unfavorable light. The over-all result, therefore, is a negative presentation. Clearly this leaves the oil industry with a pressing public relations problem. If your industry has contributed vitally to American industrial life, if it has turned to useful purposes America's one indispensable natural resource, and if it has in large part implemented our industrial growth, then high school and college students should know these things. Certainly general American history textbooks should give far more space to the oil industry's growth and development than they now give.

Oilmen, therefore, should see to it that this story is made available for all to read. As I see it, this problem can be solved by the immediate launching of a long-range program: (1) by providing our town and city libraries with a variety of dependable oil literature and by the setting up of a national research center and perhaps adequate regional libraries; (2) by lending generous support to oil and gas associations (such as the Texas Mid-Continent Oil and Gas Association), to public relations agencies and to your trade journals—all of which are doing much to build for you a friendly climate, and (3) by financing the research and objective writing of highly trained and nationally known historians and by furnishing scholarships and fellowships to superior social science graduate students, as well as those in engineering, chemistry, geology and physics, as is at present being done.

Within a few years this last-named, long-range policy would result in sound, dependable historical accounts, depicting every phase of the oil industry which in turn would furnish historians adequate reference for their proper textbook presentation of the oil industry. In my opinion, such an expenditure, if carefully directed, would become a sound investment, certainly as much so as any other exploratory operation of a company or of the industry. Such a project could be launched by a company, a regional organization, or the industry as a whole. In these days of turmoil, high taxes, and socialistic trends, the oil industry could well afford thus to look toward its tomorrow. No doubt, the future danger of oilmen may be like that facing the English steel industry of today. ★ ★ ★

[2] *The Cause of the Panic of 1893* (Boston, 1907), 6.

[3] Beard, *The Rise of American Civilization* (2 vols., N. Y., 1930), II, 177-186.

[4] Morrison and Commager, *Growth of the American Republic* (2 vols., New York and London), II, 137.

Sampling Essential to Accurate Measurement

As crude oil alone is not a homogeneous material, measurement alone is not sufficient, and therefore accurate sampling must accompany measurement by volume in order to determine how much of the quantity measured is saleable oil and how much valueless impurities, is the conclusion reached in one of the papers presented before the Third World Petroleum Congress. The paper, entitled "New Techniques in the Gathering, Measurement, and Sampling of Crude Oil," was written by three Gulf Research and Development Company men. They are: B. R. Walsh, E. W. Jacobsen, and R. J. S. Pigott.

Object of the paper is to discuss possible solutions to the problems, encountered in the gathering, sampling, and measurement of well production for control records and cost accounting. A water detector has been developed by Gulf Research, which is essentially a water sensitive capacitor feeding a capacity operated relay that performs control functions.

The authors also discuss the improved Robinson system of tank strapping and the establishment of the 5-gallon seraphin test measure as the basis standard of volume.

CALIFORNIA OIL†

West Coast operators have their own pattern of supply to fill and unusual conditions to overcome — Foresight is required equipment

R. L. MINCKLER*

For as long as I have been in the oil business, and that is a long time, California has been right on the verge of running out of oil. But we have never quite made it.

Right now, our inventories of crude oil and products are 95,000,000 bbl, which is a pretty low level, representing, as it does, only 90 days of overall supply. Current demand is running considerably in excess of current supply. These facts have once more brought upon us the pity of the rest of the industry, and once more the story is being told that California is about to run short of oil.

In judging the validity of this belief, there are certain factors, which are not adequately understood, even in the California industry, and which need careful examination.

The most important of these factors which have given a sudden spurt in the demand for California oil is the war in Korea. A year ago, the military demand in this area was only 65 to 70,000 bbl per day. It is now running 115 to 120,000 bbl per day, an increase of 50,000 bbl per day. I do not know if this increase is temporary or permanent, because I do not know the military plans for the Pacific area. So long as inventories on the Pacific Coast are in excess of working levels, I suppose it is the correct procedure to supply military needs from them, but when the surplus is all gone, I believe that we should view the supply of military products as a national problem, not as a West Coast problem. I do not believe that the California district can be expected to indefinitely supply 56 per cent of the military requirements with only 16 per cent of the crude oil production of the country, as we are now doing. I hope that the governmental agencies now being established in Washington, and the industry east of the Rockies, will accept that as a sound policy and shift some of the direct military demands from our shoulders.

We are feeling the impact of the Korean war and the accelerated defense program in areas other than direct military requirements. A year ago, the heavy fuel oil requirements of our railroads were about 55,000 bbl per day and they were declining as the railroads replaced their steam locomotives with diesel engines. The number of diesel engines has increased, but the increase in military and industrial activity has required the re-employment of laid-up steam engines and the railroad heavy fuel oil demand is now up to around 80,000 bbl per day, an increase of about 25,000 bbl per day. Even if military and industrial activity keeps up at the present high level, I believe that it is a reasonable expectation that the use of heavy oil by the railroads will decline as the use of diesel engines is expanded.

Another important demand factor is the use of heavy fuel oil for ships' bunkers. This is runing at about twice the level of a year ago, an increase of about 35,000 bbl per day. This large increase is the result of two principal factors, the Korean war which has brought a considerable number of merchant vessels out of the mothball fleet, and the fact that fuel oil bunker prices on the Pacific Coast have been very much lower than any other place in the world. I do not know if the present high level of Pacific Ocean shipping will be maintained but I believe it is a reasonable expectation that the price differential which has favored West Coast bunkering of vessels will, in time, be eliminated, and some bunker business will be shifted to East Coast, Gulf Coast, and Panama Canal ports.

A demand factor of great importance in California is the increasing use of fuel gas and fuel oil in supplying the needs of the area for electricity. There has been some increase in hydroelectric generating capacity, but the principal source of the increase in electric energy since World War II has been in steam generating plants. Before the war, the use of fuel oil in steam plants was negligible, but in 1949 it worked up to 52,000 bbl per day. In the early part of 1950, this demand dropped because of the increased availability of natural gas, largely resulting from the new supply in the Texas-California gas line, but fuel oil use in steam plants is again on the increase and can be expected to reach new high levels in the coming winter.

The effect of natural gas imports into the Pacific Coast area on oil requirements is commonly overlooked, but it is of considerable importance. The second line from Texas and New Mexico will be operating next year, and it is a reasonable expectation that within the next few years a gas line will be laid into the Pacific Northwest. These two lines will probably displace 100,000 bbl per day of oil fuel demands.

I would not have you get the idea that the future of oil demand in the Pacific Coast area is all black. This part of the country is, as you know, growing very rapidly. From 1940 to 1950, our population in the five Western states increased from 10 to 15,000,000 people, an increase of 47 per cent. This is the greatest migration of people in the history of the world. It can be expected to continue, and the appetite of our people for more and more oil products will also continue.

We think that the civilian and industrial demand in our natural market area will be about 850,000 bbl per day in 1951, the same level as at the present time. About 90,000 bbl per day of the supply required to meet that demand will come from condensates, natural gasoline, and LPG and from imports, so the crude oil requirements for our local civilian markets are only about 760,000 bbl per day. With crude oil production of about 935,000 bbl per day at the present time, it is evident that the local civilian market can be met from our own production for several years, even without any important discoveries.

Of course, there are still the military and offshore markets to be supplied. For the first 8 months of 1950, these have been as follows:

Military	90,000 bbl per day
Pacific Foreign	71,000 bbl per day
Intercoastal	88,000 bbl per day
TOTAL	249,000 bbl per day

It is the supplying of these markets that has run the total demand of this area up to 1,081,000 bbl per day and resulted in a withdrawal from our inventories of 120,000 bbl per day.

I have already discussed the problem of military supply. This has averaged 90,000 bbl per day for the first 8 months of this year, but is currently running at 120,000 bbl per day. What we used to consider a "normal" mili-

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tary requirement from this area is about 75,000 bbl per day. I expect that, with the increase in military activity, which now seems unavoidable, a new normal level of military requirements will be about 100,000 bbl per day.

Of the Pacific foreign shipments of 71,000 bbl per day, about 45 or 50,000 bbl per day are to areas where California has a transportation advantage over other potential sources of supply, so I expect that a reasonable guess is that shipments will continue at about that level so long as supplies are available here.

The intercoastal shipments of 88,000 bbl per day will probably disappear from the picture in 1951. These were shipments, principally heavy fuel oil to the East Coast, which were made to reduce surplus inventories of a year ago.

So, for the next year, we have a firm domestic market of about 850,000 bbl per day, a military market guess of 100,000 bbl per day, and a Pacific foreign market of 50,000 bbl per day, or total requirements of 1,000,000 bbl per day.

Peering into the crystal ball a little further, we see conflicting trends of demand. To increase demand, we foresee a steadily increasing population and an increasing use of fuel per capita. To decrease demand, we foresee the continued conversion of railroad engines from steam to diesel, a loss of some ship bunkering business, and the construction of new gas lines. Perhaps a reasonable guess is that these conflicting demand trends will about offset each other and that the California problem can be said to be that of meeting a 1,000,000 bbl per day demand for the next several years. That will not be the exact problem at any particular time, because emergency military demands, variations in the timing of construction of the gas lines, shortages of materials—any one of a number of variables can throw the figure one way or the other—but in a broad general way, that is the size of the problem.

To meet a demand of 1,000,000 bbl per day will require a crude oil production of a little more than 900,000 bbl per day, along with natural gasoline production and normal receipts from other districts. So another way of stating the problem is, "Can California continue to produce 900,000 bbl per day for several years?"

We are currently producing 935,000 bbl per day with perhaps 2000 small size wells shut in, so our productive capacity today is perhaps 950,000 bbl per day. We have had a very low development drilling rate for the past two years, because of the 1948 and 1949 temporary over-supply of oil. In 1948, we completed 2150 oil wells, in 1949, 1777, and in 1950, the figure will probably be about 1300. We have a rather small inventory of high-grade undrilled proved locations, and even an accelerated development drilling campaign to the level of 1948 would not run our efficient productive capacity up to much more than 1,000,000 bbl per day. At that rate, the quality of our remaining undrilled locations will be of a pretty low order and their drilling would probably not offset natural decline. Then, we would become dependent upon presently undiscovered reserves to maintain productive capacity. The record of discoveries in the past few years is not encouraging. The only first-class oil field found in California during the past 10 years is Cuyama, and even Cuyama looks pretty small in geologic time when measured up against a million barrels per day demand.

Probably there are a few more Cuyamas lying around somewhere in California, and more small fields will, of course, be found, but the present prospect is that the finding costs will be high and the rewards pretty small.

You will not that I am leaving out of consideration two important production possibilities, the Elk Hills Naval Reserve and the undoubtedly large discovery possibilities offshore.

Now, I know the political impossibility of counting the Naval Reserve as a source of potential supply. The soundest prophesy for that oil is that it will still be there after a new source of energy has displaced oil, thus continuing its so far unbroken record of complete uselessness.

In that connection, I believe it is the patriotic duty of the oil industry to keep always in mind the Elk Hills Naval Reserve situation, so that when proposals come up from the politicians to create more Naval Reserves, the truth about Elk Hills can be told.

We should understand thoroughly that from an availability of supply standpoint the Naval Reserve is the only field that was a burden to the operation of World War II. I know that it produced a trifling amount of oil, but the waste of manpower and material in getting that little dribble was fantastic. In a future World War, maybe Elk Hills will supply enough oil to run the war for a few hours, but, as in all past emergencies, our country must put its reliance upon the privately operated oil industry, which will supply more than 99 per cent of the requirements.

From the standpoint of costs—I don't know how many hundreds of dollars per barrel Elk Hills oil will finally cost, but it will no doubt have the questionable distinction of being the most expensive oil in the world.

We, in the oil business, have the duty of preventing, if we can, the creation of any more such outrageous programs.

There is, no doubt, a very large volume of oil waiting to be discovered in structures offshore from California. With the Federal government seizure of these submerged lands, they have become a political issue and for a long time will be a source of political trading and speech-making, instead of a source of energy for the use of the people. These potential reserves can not be counted into our assets for a good many years.

As I see the picture, we have plenty of oil in California for a few years more, but I believe that we are approaching finally the day when there will be a shortage of over-all local crude oil production. The old cushion of unused production capacity is about gone and productive capacity will be very close to market demand.

This situation may present a very real threat to the efficient recovery of our remaining reserves. The balance of supply and demand for individual companies will be widely different, and there may be a very great temptation for some companies short of supply to produce their reserves at too high levels, instead of efficient rates. This will delay the time of shortage, but it will add to the supply problem in later years.

As to our refinery problem, we have a statistical surplus of refining capacity. The quality of this surplus is poor, consisting mainly of straight-run units that can not profitably operate at the existing levels of crude oil and products prices. There is some inefficient refining going on now, probably as much as there is efficient capacity in idle units. I do not believe that there is any over-all excess refining capacity in this district and I think that new capacity will be built.

Also, as I see the pattern of product demand over the coming years, the light product requirements for gasoline and distillates will increase and the heavy fuel demands will decrease. I expect that additional cracking facilities are going to be required.

We are probably coming into a period where crude oil productive capacity, refining capacity, and market demand are very close to being in balance each with the others. Some very large and very important decisions affecting the future growth of the industry will have to be made. They will take foresight, skill and courage, but these are the things with which our industry is well endowed. I have no doubt whatever that we will continue to supply the people of this area with all of the oil products they wish for as long as they wish them.

* * *

TAX POLICY *and* PETROLEUM SUPPLIES†

HINES H. BAKER*

THIS analysis and discussion deals with the basic principles and philosophy underlying the income tax provisions applicable to petroleum production, and with the practical considerations involved in a sound taxing policy that will induce the risk of billions of dollars of capital that must be spent annually to discover and develop the petroleum supplies required for our economy and for national defense. The analysis is not intended to be a technical treatment of the subject. Such technical treatment would involve many details best left for discussion by tax experts, lawyers, and accountants.

Importance of Petroleum Supplies

Oil and gas are more essential to the United States today than ever before. They have now become our principal source of energy. Ample supplies of these fuels are indispensable for national security as well as for economic progress. Oil and gas are major factors in our rising standard of living. We use and need great quantities of energy provided by oil and gas for industry, for transportation, for agriculture, and for the home. Our industrial civilization depends on the continued adequacy of petroleum supplies, particularly for transportation.

Will we continue to have enough oil and gas for national security and economic progress in the years ahead? There are many technological and economic factors that must be weighed in arriving at a reasonable answer to that question. In my opinion, the United States will continue to have the oil and gas it needs for the foreseeable future provided that there is no interference with satisfactory economic incentives in the search for new petroleum reserves. The existence of reasonable economic incentives will bring about the huge investment of capital necessary to continue the exploration, development, and technological advances that make it possible to provide sufficient oil and gas for an expanding economy. In the absence of reasonable incentives, supplies of oil and gas will be affected adversely and our standards of living and national security will suffer correspondingly.

Recent developments emphasize the need for consideration of the impact of tax policy on petroleum supplies. The trend toward higher income taxes reduces the incentive and opportunity to make new investments in productive facilities for all business. It will, therefore, influence exploration and development of new petroleum resources. That risk the oil industry shares in common with other business activities. In addition, however, the pressure on the government to raise more revenue has led to dangerous proposals for changes in the tax structure which would strike a direct blow against future domestic petroleum supplies. The changes proposed early this year in the maximum rate of depletion from 27.5 to 15 per cent on the value of production would have cut virtually in half the rate that has been recognized since 1926 as necessary to provide fair treatment for this hazardous business and to encourage the further venture of risk capital in the search for new reserves. Another proposal would cut depletion still further by allowing it to apply only after gross income equaled the intangible development costs rather than over the full producing life of a property. These proposals would inevitably result in reduced exploration, smaller supplies of petroleum, and higher prices for petroleum products, all of which would hurt national security and handicap further economic progress.

Abundant supplies of oil and gas have been of tremendous benefit to all of us by providing low-cost transportation, machines to increase production while hours of work are reduced, and all the comforts of convenient and clean heat and power in our homes. Furthermore, they have been enormously valuable to the United States in time of war. In World War II, for example, petroleum products for ships, planes, tanks, trucks, and other equipment carried our fighting forces to victory, with a saving of immeasurable value in lives, time, and money. Abundant oil supplies meant victory for our forces, while inadequate oil supplies spelled ultimate defeat for our enemies. Surely the government will not seriously consider tax measures that would jeopardize national safety and have a disastrous effect on our future economic progress if it understands the principles and facts involved in this important matter.

The Principle of Depletion

Since the first income tax law was passed in 1913, Congress has recognized that such laws must take into account the depletion of national resources incident to production. Depletion is comparable with depreciation on other capital assets. Both depreciation and depletion must be recognized in income tax laws in order to avoid the fundamental mistake of taxing capital as though it were income. The Sixteenth Amendment to the Constitution authorized tax on income only, and not on capital. Whenever income taxes are imposed, it becomes necessary to define and distinguish between capital and income so that the receipts of a taxpayer that represent the return of capital are not subjected to taxation as though they were current income. This distinction

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is essential to protect capital assets, including basic natural resources, so that capital may be replaced and additional capital attracted into the productive operations that create our income.

The problem of measuring capital is relatively simple in the average business. In most activities of normal risk the capital is about the same as the investment in productive facilities. If a firm invests $1,000,000 in a plant that will last 20 years, its depreciation is at a rate of $50,000 a year. Such depreciation is deducted from gross income each year in arriving at net taxable income. That principle applies with equal force to the refining, transportation, and marketing activities of the petroleum industry. In the case of oil and gas exploration and production, however, as for all other natural resources involving considerable hazard, investment in a property is not an adequate measure of capital value created by the developer of new resources. To encourage continued exploration, depletion provisions must take into account the capital value of the resources themselves.

What is the capital that should be allowed for the depletion of natural resources discovered on a property as a result of hazardous exploration? It is not merely the investment in a particular productive property, for under such a narrow interpretation the capital risked and lost in nonproductive ventures would be entirely overlooked. It takes the exploration of many leases to locate one structure with sufficient promise to warrant an exploratory test, and less than one in five such tests discovers a new field. That means that the capital risked in the search for oil is much more than five times the amount spent in locating the discoveries. In such circumstances, it would be unfair by any reasonable standard to limit the capital returnable by depletion to the amount spent on productive properties. Even if an operator has sufficient other income against which he can deduct his non-successful expenditures (which might not be the case for one seeking to get started in the business), that only reduces his taxes without actually returning the capital lost or providing an opportunity to earn a profit on it.

A reasonable investor could not afford to venture large sums of capital against substantial odds if he were limited to recovering as capital only what he spent on the discoveries while required to absorb all the losses on the numerous failures. There must be the hope of a return in case of success greater than the amount risked on the successful venture in order to attract sufficient operators into any business involving large risks. Return to the most successful operators may seem large when viewed alone, but the average return is apt to be quite small. The hope and realization of large reward for unusual success is indispensable to induce enough operators to take the risks involved in the search for new oil. Naturally, the reward should be in proportion to success in finding oil. The value of a new discovery is governed by the volume of oil discovered, and not by the amount of money spent in locating it. As the property is depleted of resources, that value declines. Depletion provisions must reasonably consider that value. It is proper and reasonable, therefore, to measure depletion by capital value in the case of a resource, such as oil, which requires a hazardous search for its discovery.

As a property is produced it experiences a decline in value for two reasons: (a) the depletion of the oil and gas, and (b) the depreciation of the wells and equipment that make possible the production. Provision must be made for the consideration of both depletion and depreciation in the income tax laws to deal fairly with petroleum producers, and all producers of natural resources in general, as compared with other business activities. Congress has studied this question carefully since the introduction of income tax laws and very early in the history of those laws worked out a fair and sound system that has been in effect for more than a quarter of a century. A review of that history demonstrates the reasonableness of the present tax provisions relating to oil producing properties.

Fair treatment concerning allowance for intangible development costs and depletion has permitted the oil industry, despite the great risks, to keep the United States abundantly supplied with its products. This is not the time to experiment with a tax program that restricts development of our oil resources.

History of Depletion Provision

The first income tax law was passed by Congress in 1913. It included provision for "a reasonable allowance for depletion of ores and all other natural deposits." The practical definition of a reasonable depletion allowance remained to be determined through experience. After a brief unsatisfactory experiment in the 1916 law with depletion based on cost, except for properties producing on March 1, 1913, for which the value on that date could be used, Congress decided on the principle of discovery value for depletion in the Revenue Act of 1918. This Act provided that depletion should be based on "the fair market value of the property at the date of the discovery, or within thirty days thereafter." By this action Congress placed operators who discovered properties after March 1, 1913 on the same basis as those who had discovered properties prior to that time; that is, it reaffirmed *value* rather than cost as a basis for depletion.

Administration of the 1918 Act required that a "fair market value" be determined *after* the discovery of oil. In practice, this provision proved very difficult to administer. There were so many leases and such wide differences of opinion as to "fair market value" that the Bureau of Internal Revenue was swamped with endless detail and controversy. After several years of such difficulty a Senate Select Committee was created to investigate the administration of the tax laws. The work of that committee led to adoption in 1926 of the formula for depletion still in effect today.

The Revenue Act of 1926 maintained firmly the principle of value as the proper basis for depletion, but introduced a new method of computation. The change was made to simplify administration and achieve a greater measure of justice among taxpayers. One government witness, the attorney for the Senate Committee, testified as follows: "I believe that it is absolutely imperative that some method of determining depletion be figured out as a substitute for the present method of basing it upon valuations." He also said that a greater measure of justice in the long run could be established if Congress were to fix depletion allowance at a percentage for all taxpayers on the sale value of their products. A representative of the Treasury Department said it would be a great step in advance if something could be done to relieve the Department of the necessity of making the valuations required by the Revenue Act of 1918. He said that if Congress could determine a proper rate the only question would be how far it was willing to go in adopting such rate in the interest of simplicity as against following the exact logic of the principle.

After considering all the testimony, the Senate Finance Committee recommended in the interest of simplicity and certainty in adminstration that the allowance for depletion in the case of oil and gas wells should be 25 per cent of the gross income limited to an

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amount not in excess of 50 per cent of the net income. The rate recommended was based on the experience in applying the discovery value provisions of the 1918 Act. In discussing the proposal before the Senate, Senator Reed said that the rate was a happy medium for different kinds of properties and that "if there is any error in the 25 per cent figure it is in favor of the government." In the debate in the Senate on the committee's recommendations, the term "real capital" was used in referring to the need for depletion based on discovery value or its equivalent, which Congress proposed to measure as a per cent of the sales value. The Senate increased the rate from 25 to 30 per cent when it adopted the bill, but a rate of 27.5 per cent was later agreed upon by the Conference Committee which reconciled the views of the House and the Senate. The depletion provisions adopted in the 1926 Revenue Act have subsequently been reviewed a number of times, but the testimony and evidence that the principle and amount of percentage depletion are fair and reasonable has caused Congress to reject repeatedly the proposed changes. The most recent endorsement of percentage depletion was made this year by Congress after extensive hearings and careful review of the question.

How Percentage Depletion Has Worked

Percentage depletion has now been in effect a quarter of a century. In that period of time it has worked simply and equitably. By protecting the capital value developed by successful producers, as intended by Congress, it has attracted into the search for and development of oil the billions of dollars that have been and will continue to be required to supply this country with increasing quantites of oil and gas. Domestic production of petroleum liquids in 1950 will be about two and a half times as much as in 1926, and the marketed production of natural gas this year will be about five times as much as in 1926. These increased supplies of oil and gas have accounted for all of the additional energy consumption in the United States since 1926. They have added enormously to the productive capacity of the United States in agriculture, in industry, in transportation, and in other basic economic activities.

Liquid fuels are the indispensable motive power of the marvelous transportation system of this country that has become part of our way of living, as well as a means of low-cost, high-speed movement for all the goods we use. Because of abundant supplies, the price of petroleum products has been so low that the great mass of the American people have enjoyed the benefits of liquid fuels to an extent unequaled anywhere else in the world. The oil industry sells gasoline for less today than in 1926, and the quality is so much better that we can realize 50 per cent more power now from each gallon. Such achievements explain why we can afford to use petroleum products in such large quantites. Per capita consumption of petroleum in the United States is 20 times as much as in the rest of the world. That difference is a major factor in our superior productivity and standards of living. The tax provisions with respect to percentage depletion have been part of the economic structure that permitted the petroleum industry to expand so remarkably and serve us so well during the last 25 years. It does not make sense that we should even consider tampering with reasonable tax provisions that have produced such great benefits for all of us.

Percentage depletion, in effect, substituted as a deduction the current capital value of oil as it is produced for the discovery value determined at the time the lease first became productive. Over a period of rising and falling prices, the two methods give practically the same result. Operators who develop oil at a time of high prices are allowed less depletion in a period of low prices under percentage depletion than the capital value at the time of discovery. On the other hand, operators who develop oil at a time of low prices are allowed more depletion in a period of high prices under percentage depletion than their capital value at the time of discovery. Over a full business cycle these differences are largely offsetting, although percentage depletion gives the appearance of providing some advantage in a period of high prices because it is related to replacement costs. For the ordinary business, depreciation is related to actual investment and not to replacement costs. The disadvantages of this principle in periods of high prices are offset, however, by its advantages in a time of low prices when depreciation provisions on investments made during the boom phase of the business cycle are more than enough to replace the equipment being worn out. Thus over a full business cycle, percentage depletion and depreciation give comparable results. Percentage depletion works out very fairly among different operators, furthermore, because it allows at all times a deduction related to the cost of replacing oil in order to stay in the business with unimpaired physical assets.

The principle of percentage depletion now seems accepted beyond question, but sometimes the question is raised whether the rate of 27.5 per cent is correct. The best economic evidence of the reasonableness of this rate is its close reflection of the capital value of oil in the ground. At the present time on an average price of crude oil of $2.55 a barrel the maximum percentage depletion is 70 cents, and the average depletion is about 63 cents because of the limitation to 50 per cent of net income. This depletion allowance agrees very closely with the discovery value of oil in the ground. In Texas, for example, a number of sales of properties have been made in recent years at a price of about $1 a barrel for proved, developed reserves. Deducting from this price a typical cost of 30-35 cents a barrel (which is in addition to all the exploration expense), indicates a discovery value of about 65-70 cents.

Depletion at the rate of 27.5 per cent has operated similarly to reflect the capital value of oil reserves in the ground over the full range of prices experienced since 1926, when the average price was $1.88 a barrel and the provision meant a maximum allowance of 51.7 cents on that price. In the years 1930-1940, for example, the price of crude oil averaged only about $1 a barrel, on which the maximum depletion allowance was 27.5 cents. That amount was in line with the capital value of oil in the ground at that time. Similarly, in the post-war period percentage depletion continued to reflect the changing capital value of oil in the ground as increased costs in the search for oil and inflation generally brought about rising prices. Such relations demonstrate that the depletion provision is still operating as intended in permitting the recovery of capital value, and that there is no justification for reducing the rate.

Survey Adds Evidence

A recent survey by the Mid-Continent Oil and Gas Association of companies producing about half of the oil in the United States provides further evidence that the depletion rate of 27.5 per cent is still right. In the years 1926-1949 these companies spent on exploration alone, not counting an even larger amount for the development of productive wells, nearly as much money as their total allowable depletion. The expenditures for exploration have moved up and down with the allowable depletion. Such a relation proves that a reduction in the rate of percentage depletion would affect the expenditures for exploration and therefore, the future supplies and prices of oil. The only way to avoid a reduction of the amount risked in the search for oil if the depletion allowance were cut would be for

changed conditions of supply and demand to result in prices sufficiently higher to make up the difference. To maintain the same incentive, the industry as a whole would have to receive additional revenue equal to the amount of the added taxes. Even if circumstances brought about price increases equal to the added taxes, a cut in percentage depletion would still reduce the incentive for exploration and development because of the fear it would introduce with respect to possible further changes in the future.

The current rate of percentage depletion also appears reasonable in relation to industry experience as well as to that of the companies included in the survey of the Mid-Continent Oil and Gas Association. Cost estimates based on the total drilling and exploration activities of the industry indicate that in 1949 the oil industry spent more than a billion dollars on exploration alone, in addition to another billion dollars on drilling and equipping productive wells. In spite of the high rate of operations in 1949, exploration expenditures for the industry apparently were fairly close to the total depletion allowed under the present rates.

Another test of whether the prevailing percentage depletion provision has been too liberal is the rate of profit. If the tax provisions applicable to the depletion of oil production have been too liberal it should show up in a rate of profit higher for the oil industry than for other industries and should result in attracting into oil production more capital than necessary. Actually, available statistics show that the rate of earnings of corporations in the petroleum industry has averaged less than that of corporations engaged in manufacturing and trade.

The evidence on earnings in the years 1938-1949, the most prosperous period in the history of the United States, disproves the common misconception that the oil business is extremely profitable. During this time earnings on net worth averaged about 11 per cent for large corporations in the oil industry compared with 12 per cent and 13.6 per cent for comparable corporations in manufacturing and trade, respectively, as shown by the annual studies of corporate net income by the National City Bank of New York (See Table 1). Only in the exceptional year of 1948 was the rate of earnings for oil corporations slightly higher than for the manufacturing and trade groups. A sharp decline in oil earnings followed immediately in 1949, reducing the average return again to a level less than that in manufacturing and trade. Another study of financial results for 30 large oil companies by the Chase National Bank shows average earnings on invested capital of less than 10 per cent for the period 1938-1949, a rate slightly lower than for the group of corporations included in the National City Bank reports.

TABLE 1. Net Income and Rate of Return of Leading Corporations.

	Manufacturing (NCB)[1]			Trade (NCB)			Petroleum products (NCB)		
	Net income (mil. $)	Net worth (mil. $)	Rate of return per cent	Net income (mil. $)	Net worth (mil. $)	Rate of return per cent	Net income (mil. $)	Net worth (mil. $)	Rate of return per cent
1938	1,067.5	23,209.8	4.6	154.5	1,788.9	8.6	190.0	4,119.7	4.6
1939	2,095.5	25,125.2	8.3	211.7	1,896.3	11.2	230.4	4,649.3	5.0
1940	2,628.1	25,597.8	10.3	205.0	1,945.6	10.5	252.0	4,689.9	5.4
1941	2,925.6	23,807.9	12.3	233.5	2,122.1	11.0	306.5	3,583.6	8.6
1942	2,521.5	24,905.9	10.1	216.2	2,177.4	9.9	259.0	3,693.2	7.0
1943	2,729.5	28,474.1	9.6	235.3	2,334.8	10.1	498.9	6,196.8	8.1
1944	2,889.8	29,556.9	9.8	244.6	2,408.3	10.2	624.9	6,443.0	9.7
1945	2,997.9	32,167.8	9.3	275.2	2,534.0	10.9	596.7	6,778.7	8.8
1946	4,111.9	34,005.4	12.1	624.5	2,850.2	21.9	769.6	7,174.3	10.7
1947	6,317.0	37,062.3	17.0	615.8	3,368.4	18.3	1,215.9	7,712.5	15.8
1948	8,172.4	44,959.8	18.2	707.7	3,880.2	18.2	1,930.1	9,160.6	21.1
1949	6,998.5	50,656.0	13.8	577.0	4,358.2	13.2	1,420.7	10,761.4	13.2
Avg	3,787.9	31,627.4	12.0	358.4	2,633.7	13.6	691.2	6,246.9	11.1

	Oil and gas producing (NCB)			Combined petroleum products and oil and gas producing (NCB)			30 oil companies (CNB)[2]		
	Net income (mil. $)	Net worth (mil. $)	Rate of return per cent	Net income (mil. $)	Net worth (mil. $)	Rate of return per cent	Net income (mil. $)	Invested capital (mil. $)	Rate of return per cent
1938	19.9	317.6	6.3	209.9	4,437.3	4.7	300	6,203	5.1
1939	15.8	298.0	5.3	246.2	4,947.3	5.0	321	6,290	5.4
1940	12.7	297.8	4.3	264.7	4,987.7	5.3	377	6,234	6.3
1941	22.1	265.6	8.3	328.6	3,849.2	8.5	530	6,352	8.8
1942	24.6	272.7	9.0	283.6	3,965.9	7.1	403	6,494	6.6
1943	27.6	233.5	11.8	526.6	6,430.3	8.2	510	6,751	8.0
1944	30.9	247.9	12.5	655.8	6,690.9	9.8	640	7,106	9.6
1945	31.0	273.7	11.3	627.7	7,052.4	8.9	602	7,485	8.6
1946	35.3	292.9	12.1	804.9	7,467.2	10.8	763	8,002	10.3
1947	70.0	352.0	19.9	1,285.9	8,064.5	15.9	1,219	9,054	14.9
1948	134.7	387.3	34.8	2,064.8	9,547.9	21.6	1,877	10,631	19.8
1949	107.9	496.2	21.7	1,528.6	11,257.6	13.6	1,368	11,465	12.8
Avg	44.4	311.3	14.3	735.6	6,558.2	11.2	743	7,672	9.7

[1] NCB—National City Bank.

[2] CNB—Chase National Bank.

The figures on the earnings of the large oil companies generally reflect the combined results of integrated operations in exploration, production, transportation, refining, and marketing. The question may be raised whether profits on oil production are not unduly high even though profits on combined integrated operations are less than the average for corporations in manufacturing and trade. The available evidence shows that even the most successful companies specializing in oil and gas production alone earn only a slightly higher rate of return than manufacturing corporations in spite of the much greater risks that they take. The reports of the National City Bank, for example, show that some 40 oil and gas producing companies, with a gross income indicating that they account for about 8 per cent of the value of all oil and gas production, earned an average of 14.3 per cent on their net assets in the years 1938-1949 compared with 12 per cent for manufacturing corporations and 13.6 per cent for corporations engaged in trade (See Table 1.) This sample of producing companies is so small that it hardly affects the average for the industry when combined with the large integrated companies. It must also be noted that the companies in the sample are the highly successful ones that have attained sufficient size to be included in this study of corporate earnings. The results would be less favorable for a typical sample of average producers. Treasury Department figures for the year 1947, for example, show that 1416 out of 3607 oil and gas producing companies reported losses in an aggregate amount of $46,000,000, compared with the net income of $264,000,000 reported by the successful firms. The earnings on net assets overstate the rate of earnings for petroleum producers because some of these producers do not include intangible development costs as capital assets and none of them include in assets the discovery value of producing properties. Finally, it may be noted that while the earnings of this small group of producers appeared high in 1948 (34.8 per cent on net assets), that exceptionally profitable result for the best year in the history of the industry was not much more than the 30.8 per cent reported for the automobile industry in 1949 and the 30.2 per cent reported for cotton goods manufacturing in 1948 in the National City Bank study. Such exceptional years must be considered in the light of the average earnings over a period of 10 years or more.

Large oil companies have experienced a smaller net return on net assets than manufacturing corporations, and in addition have also paid out a smaller per cent of earnings as dividends than other corporations. Reports of the Department of Commerce show that in the 10-year period 1939-1948, large oil companies paid about 38 per cent of their earnings as divi-

dends, whereas manufacturing corporations generally paid more than 48 per cent. An important reason why oil companies have had to retain a large part of their reported earnings is the fact that accounting methods based on cost fail to give adequate consideration to the decline in value of productive properties due to depletion. Depletion charges based on capitalized lease costs as customary in financial reports to stockholders are totally inadequate in case of oil production to permit replacement of the properties depleted, and must be supplemented by retaining part of the reported earnings to maintain the physical reserves and equipment in order to stay in the business.

The inadequacy of traditional accounting methods in relation to petroleum production creates an erroneous impression as to income tax payments by oil companies compared with other businesses. These methods result in overstating the real income properly subject to income taxes for two reasons. In the first place, they do not take into account that much of the reported income from production results from the sale of a capital asset (oil) and is different from ordinary income. The return of the capital value of oil in the ground, measured by percentage depletion, merely gives the producer a chance to maintain his real assets constant by replacing the oil produced. In the second place, the income shown in oil company financial reports generally fails to deduct the regularly recurring intangible development costs that must be made merely to maintain productive capacity. The oil producing business, unlike manufacturing and trade, requires constant expenditures of money for exploration and drilling merely to stay even from one year to the next. Allowance for these facts, which are not properly recognized by traditional accounting methods, is provided for in income tax laws to place oil producers on a comparable footing with other investors. The rate of income tax payment on the *reported income* of oil producing companies necessarily must be less under these circumstances than for ordinary business to result in equal treatment with respect to *real current income*.

The principle and rate of percentage depletion is right according to the evidence of past and current operations not only for the industry as a whole, but also for all operators regardless of size. Small operators unquestionably need it, as amply demonstrated by evidence presented before Congressional committees this year and in earlier hearings on depletion. The same provision is equally necessary and fair for large companies taking exactly similar risks. Size does not protect a company against any of the real risks in oil exploration and development. Large expenditures in exploration provide no guarantee as to the number or size of discoveries, nor does the drilling of numerous wells provide any assurance that the value of the oil developed will equal or exceed the money risked. Although large companies drill only about 20 per cent of all dry holes, they drill the deeper, more expensive wells and carry on the bulk of the geological and geophysical operations. For example, a survey by the Mid-Continent Oil and Gas Association shows that the dry holes drilled by large companies are 80 per cent deeper on the average than dry holes drilled by all other operators. This and other related evidence leads to the conclusion that on the whole, the money risked by large companies in the search for oil, according to the best indications available, represents about the same proportion of the total risked as their net share of production. Therefore, the equal treatment with respect to depletion that Congress has provided for all operators regardless of size is in keeping with the facts and needs of the industry's operations. It would be as absurd and unreasonable to have different depletion rates on the basis of size as it would be to have different depreciation rates for identical manufacturing operations depending on the number of machines operated.

The percentage depletion provision has worked admirably to protect the capital value of oil production so as to encourage operators to risk once again in the search for oil the capital recovered in the course of production. The provision has worked to encourage all operators regardless of size. It has become a part of the economic structure of the industry and cannot be changed without serious influence on the entire cost-price relations in the petroleum industry. Any increase in taxes would result in either an offsetting increase in prices, to the detriment of consumers, or in less development of new resources to the disadvantage of national security and future economic progress.

Tax Provisions on Intangible Development Costs

In connection with the proposal to reduce the rate of percentage depletion, it was also suggested to Congress early this year that depletion become applicable to a property only after its gross income equaled the intangible development costs. The argument advanced in support of this suggestion was that the application of both percentage depletion and the option to expense intangible development costs resulted in a double deduction. The basis of this argument is a Treasury regulation that if intangible development cost is capitalized it must be recovered as depletion. There is no logical basis in fact for treating intangible costs as assets recoverable through depletion. Hence, it is imperative to provide some reasonable basis, such as that included in the reg-

World Oil Price Structure Is Changing

The future world oil price pattern, as a result of the developing changes of supply and demand will be closer related to the U. S. price structures than it has in the past, Walter J. Levy, economic consultant, New York City, believes. In a paper, "The Past, Present, and Likely Future Price Structure for the International Oil Trade," presented before the Third World Petroleum Congress at The Hague, Levy concluded that the maximum and minimum price range that has already established itself for Middle East crude oil is likely to continue. He added, however, that upon conclusion of the Middle East pipe line capacity, quotations for Middle East crude oil are likely to be shifted from a Persian Gulf basis to an Eastern Mediterranean basis.

Middle East and European product prices are likely to establish themselves in accordance to local competitive conditions, independent of U. S. Gulf prices, Levy predicted. He added that Caribbean oil is likely to establish itself within a maximum and minimum range that would be related to the U. S. price level with actual prices within that range being determined by competition with Middle East Oil, and competition between the various suppliers within the Caribbean. Levy presents a price structure in his paper, that would assure the world abundant supplies of oil at reasonable prices, and states that confusion and conflict will result during the period of transition from the old to the new supply pattern. A price structure closely resembling the one he has presented will ultimately be worked out.

ulations since 1918, for the recovery of intangible development costs apart from depletion.

The fallacy of the "double deduction" argument and the soundness of the present tax policy in allowing both percentage depletion and the expensing of intangible development costs becomes evident from a consideration of the economic bases of these provisions.

In addition to the money risked in the search for oil, an operator must make substantial expenditures in developing production if he is successful in finding it. These expenditures are of two kinds: (a) The intangible development costs of drilling a hole, and (b) the tangible development costs for casing, tubing, pumping equipment, and other items which have a salvage value if the well is abandoned. The investment in tangible equipment is recovered through depreciation over the anticipated life of the property, in the same manner that investments in tangible facilities in other businesses are recovered through depreciation. Intangible development costs, however, do not result in any asset which can be sold or salvaged in itself. They constitute a current expenditure of money for "wages, fuel, repairs, hauling, supplies, etc., incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas" as provided for by the regulations of the Treasury Department. The fact that such expenditures do not result in a tangible asset which could be sold or salvaged for any other purpose sets them apart from and calls for a different method of treatment than the investment in tangible assets.

Since 1918, the regulations applicable to the determination of income have granted the taxpayer the option to charge intangible development costs as an expense when incurred or to capitalize them for recovery over a period of time. The option to expense intangible development costs, rather than to capitalize and recover them as depreciation over a period of time, does not change the fact that the operator is allowed to deduct his expenditure only once. The standard industry practice of charging intangible development costs as an expense and depreciating investments in tangible equipment was generally applied and fully recognized by the Bureau of Internal Revenue and Congress at the time percentage depletion was adopted in 1926. These different provisions were allowed because, taken all together, they were recognized as proper and necessary to protect against taxation as income the capital expenditures made in development as well as the capital value created through discovery.

The Treasury Department has alleged that the option to expense intangible development costs permits an operator to have a substantial income without paying much income taxes. It presented hypothetical illustrations of what it called "the method of avoiding tax liability," implying that there is something wrong with the present system. The point at issue is really not tax avoidance, but whether an income tax law shall impose a levy on capital. After all, the expenditure of money for intangible development costs merely changes the time of tax payment. Allowing all intangible development costs, even though they delay the date of income tax payments, is essential to avoiding a taxation of capital as income. If an operator's expenses on intangible development costs are large in one year and act to reduce his income taxes, that simply means that he is developing properties from which he will later have income subject to income taxes. Spending money on intangible development clearly reduces the immediate income available to the operator. If an operator had to pay income taxes on the money he spends on intangible development, frequently he would not have sufficient resources with which to carry on necessary development.

The answer to the false argument that depletion and the option to expense intangible development costs constitute a double deduction can be summarized by noting that these distinct provisions for two separate purposes are both necessary to provide fair tax treatment, and that Congress adopted percentage depletion and determined the proper rate with the full knowledge that intangible development costs were allowed separately as an expense and would not be covered by the depletion provision.

Conclusion

This analysis has set forth the reasons for and the importance of the existing tax provisions relating to oil and gas production. It has shown that percentage depletion at the rate now allowed in the law is representative of the capital value created through the discovery of oil and that the protection of such capital value is essential if operators are to continue to risk funds in replacing petroleum as it is produced. It has also shown that the option to expense intangible development costs is reasonable and should not be offset against percentage depletion which was consciously adopted by Congress for a different purpose. These provisions of the tax laws were adopted by Congress after careful study, and have been endorsed again and again through the years in recognition of the peculiar nature of the petroleum producing business and the great importance of petroleum for national security and economic progress.

It is clear that the investment of capital in productive machines is the basis of economic progress in this country. Those machines require enormous quantites of energy to make them useful. Petroleum is particularly important to the modern economy, for it is the basis of its low-cost transportation and distribution system, as well as an important factor in the production of goods at factories. Liquid fuels are of the greatest significance to national defense, for the equipment of the modern military establishment depends exclusively on them for power. In these circumstances, adequate supplies of petroleum assume an enormous importance to the public interest. Congress has recognized this importance and has taken steps to protect operators in this hazardous industry against unfair taxation and to encourage operators to continue to risk more and more capital in the search for and development of the increasing supplies needed for an expanding economy. It would be most harmful to the public interest to set forth now on a backward policy which would discourage the development of new oil resources.

To protect itself against aggression and to make comparable progress in the second half of the twentieth century with its remarkable achievements during the past fifty years, the United States must have an adequate supply of fuels. The present tax provisions are indispensable to the continued adequacy of petroleum supplies for the future. It would be a mistake to make experimental changes in reasonable provisions that have worked so well in the public interest. The damage of such experimentation could not be easily corrected even by returning to the present basis, for it is only the continuity of fair laws over a period of time which creates confidence on the part of the investor that he may count on reasonable treatment for the future.

The price of a mistake in tax policy with respect to petroleum would be very high. In the absence of fair tax treatment and reasonable incentives, the petroleum industry of the United States will find less oil and gas and this country will have to develop much more expensive synthetic substitutes, paid for by consumers and taxpayers. Given a continuation of reasonable and fair tax provisions, the petroleum industry can be counted upon to do its part in providing ample supplies of fuel for the future. * * *

BIG MODERN COOPER-BESSEMER GMW'S

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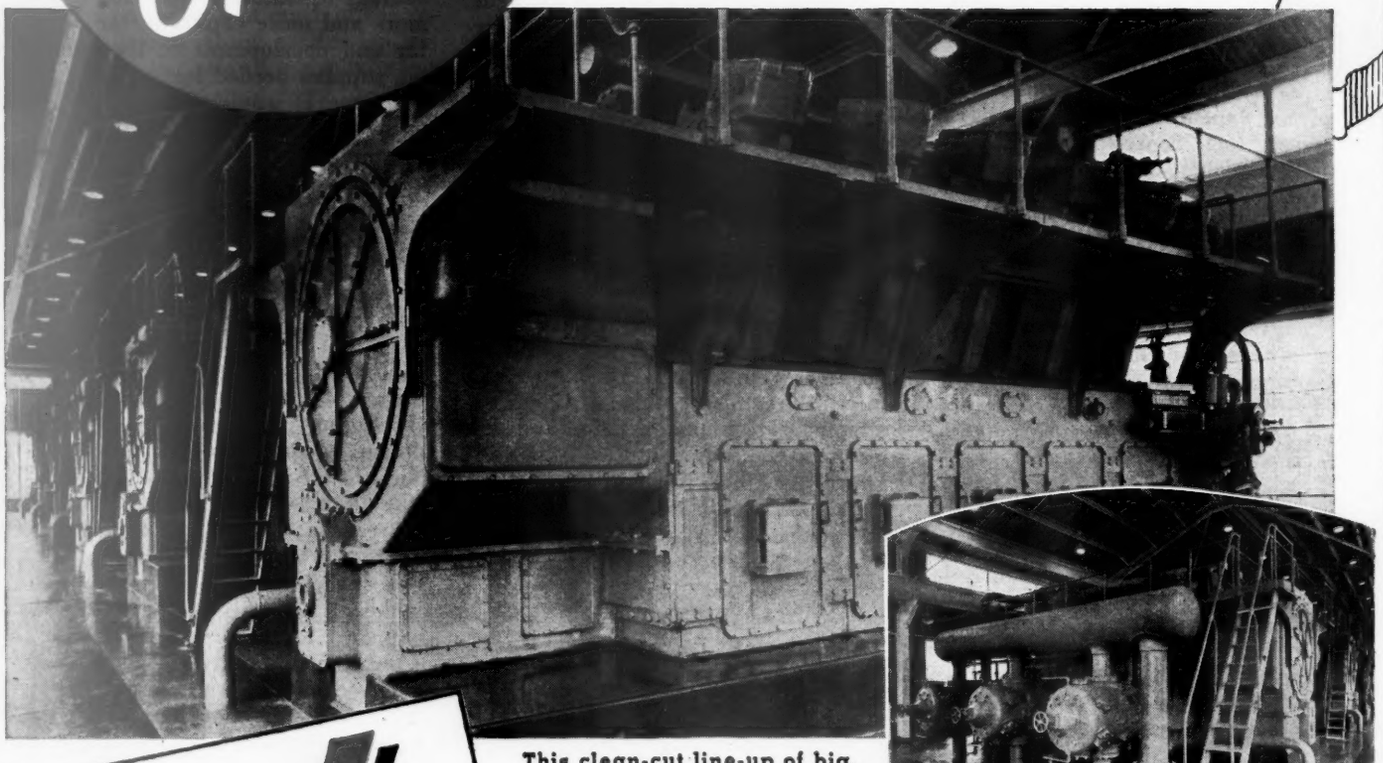

This clean-cut line-up of big, modern GMW's is duplicated in all of the Cooper-Bessemer-powered Transcontinental stations. Shown here from the crank door side, each of these 10-cylinder V-angle GMW's is rated 2500 bhp.

Same units shown from compressor side. Like the GMW in the foreground, each unit drives 3 compressor cylinders.

V ANGLE

Compressors

New York Washington, D. C. Bradford, Pa. Parkersburg, W. Va.
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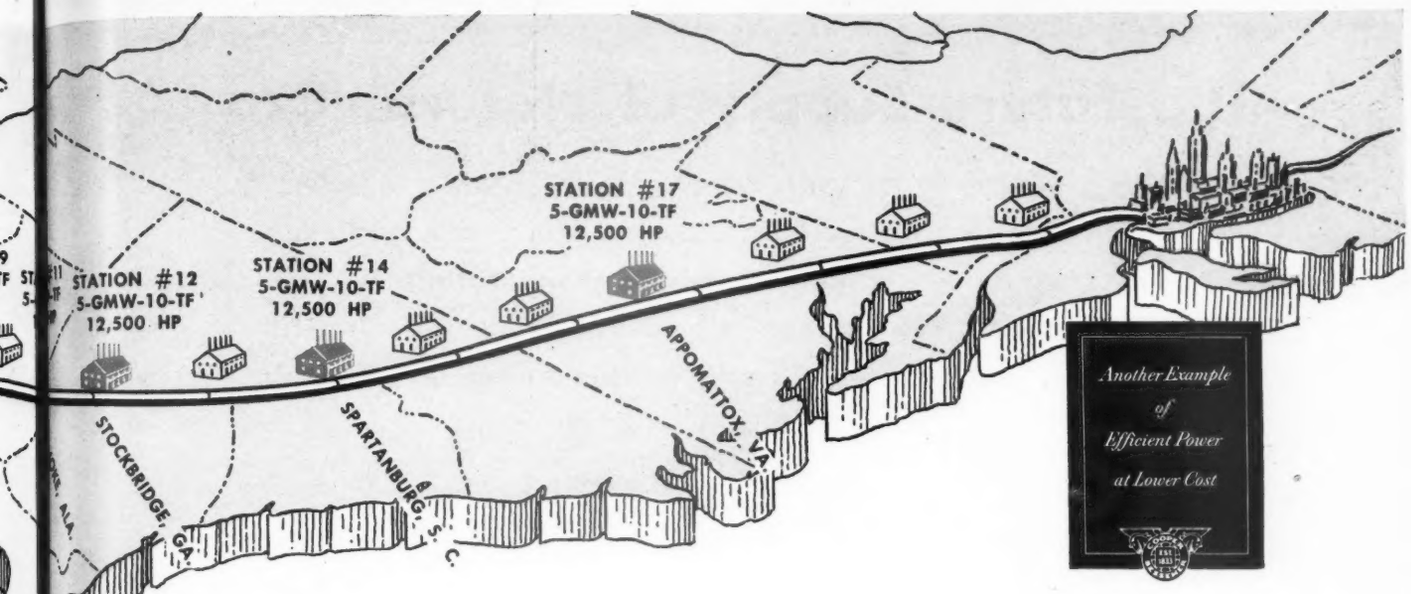


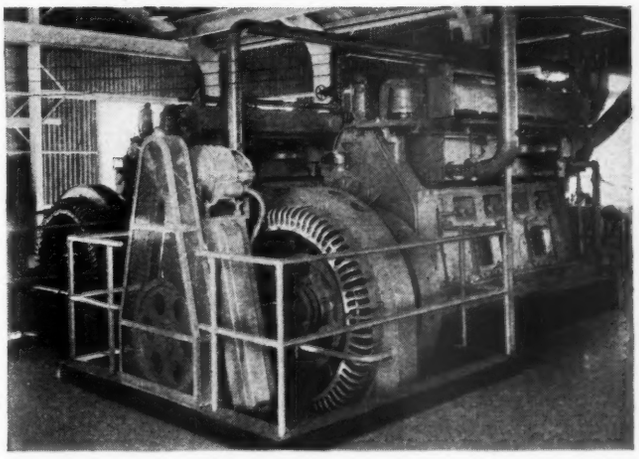
the 1,840-mile Transcontinental Line

WHILE the huge Transcontinental Line was still in the initial planning stage, news broke of a Cooper-Bessemer compressor engine development almost too good to be true. It was the now well-proved GMW—not only the most powerful, most compact "angle" compressor engine ever built, but utilizing fully the new Cooper-Bessemer high compression development, permitting fuel economies never before attained.

Fish Engineering Corp., responsible for the design, engineering and construction of the line, was quick to see that GMW's could save Transcontinental hundreds of thousands of dollars in installation, housing, cooling and piping costs and fuel consumption.

Today, as indicated on the system map, Transcontinental has 43 GMW's, totaling 107,500 horsepower, divided between 9 of the line's stations. These modern, dependable units are more than living up to expectations, just as they are on other important lines.

If *your* plans call for compressor horsepower, be sure to check on the latest Cooper-Bessemer V-angle developments. These units, GMW's, GMV's and GMX's are built in a complete range from 220 to 3000 bhp.



In addition to the GMW compressors serving on the Transcontinental Line, 7 of the stations are each equipped with 3 Cooper-Bessemer JS-5, 375 hp gas engines driving generators for all electric power needs.

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The Future Supply of Natural Gas†

The planning and projects of industry, economics, and even politics are influenced by the amount of natural gas we will find in the United States. This author is more optimistic than most and here he tells why he thinks reserves are high

LYON F. TERRY*

THE American gas industry is having an unprecedented boom in the construction of natural gas pipe lines. The existing lines to those large cities now being served with natural gas have been enlarged and are being further extended. Natural gas from Texas has reached Philadelphia and Staten Island, will soon reach all of New York City and vicinity, Buffalo and San Francisco, and there are proposals to bring natural gas to New England and to the Pacific Northwest. Hence, it may be timely to again inquire into the future supply of natural gas.

The status of the nation's known reserves of natural gas is reported annually by the American Gas Association Committee on Natural Gas Reserves. The Chairman of that Committee is N. C. McGowen, president of the United Gas Corporation and a former president of this Association, and the committee is composed of some 60 engineers and geologists scattered throughout the country. Having worked with many of these men in times past, I am satisfied that their estimates are reliable and that they are rendering a most valuable and dependable service to the gas industry. The committee's last report showed estimated proved reserves of natural gas in the United States as of December 31, 1949, to be 180 trillion cubic feet, and net production for the year 1949 of 6.25 trillion cubic feet. It would seem at first glance that such reserves should be adequate for the nation's requirements, but the 6.25 trillion produced per year is being increased rapidly and will probably reach 10 trillion before 1960, so that there may be some question as to whether the presently *proved* reserves of gas are sufficient to justify the newly proposed pipe lines. But the proved reserves need not be considered alone, as a larger element of the future supply will be the yet undiscovered deposits of natural gas to be found in the future in the search for oil as well as for gas.

Oil and Gas Production

The business of producing natural gas is a sister industry to, and in a sense a part of the petroleum industry. Most natural gas is produced by oil companies, while considerable oil is produced by gas companies. Production of natural gas in this country approximates 18 billion cubic feet per day compared with 5,900,000 bbl daily of crude oil. In terms of Btu's, the production of natural gas is only 50 per cent of the production of oil, but the proved reserves of natural gas amount to about 125 per cent of those of oil. The origin, occurrence, and search for oil and natural gas are closely related and the study of the future prospects of natural gas involves both of these natural resources.

The original source material for the formation of oil and natural gas was apparently the marine life that once inhabited ancient seas and was buried in the sediments laid down in those waters. Layer upon layer of such sediments under increasing pressure has been consolidated in the course of millions of years into the present sedimentary rocks. Thus, deposits of oil and natural gas are now found in the sedimentary formations of the earth in many different types of local folds, anticlines, salt domes, reefs, and traps situated in the sedimentary basins that once comprised ancient seas. The search for geologic structures that may contain such deposits will continue as long as the prospect of finding additional reserves will warrant the cost. Exploration is based upon geological studies aided by specialized techniques involving the use of the gravity meter, magnetometer, seismograph, and microchemical surveys of the underground from the surface, and studies of drilled areas through the logging of wells by coring and by electric and radioactivity measurements of the subsurface encountered in well holes, etc. The ultimate testing is accomplished by drilling as only the drill can conclusively determine the presence of oil or gas. Currently, some 470 geophysical parties are operating in the search for oil and gas and more than 9000 wildcat tests were drilled in 1949 in this country outside of proved areas, in the hope of finding new deposits. This is the effort that the gas industry must depend upon to find the supply of natural gas for the future. And the gas industry may well benefit by examining the studies of some of the scientists of the petroleum industry as to the prospects for finding additional supplies of oil.

Ultimate Oil Production

The subject of the ultimate supply of petroleum was discussed by Wallace Pratt[1] in 1942 and 1944. Since then, additional territory has been explored, deeper wells have been drilled, new evidence has been revealed, and the ultimate oil and gas resources of the country are believed to be more than could then be counted upon. One of Pratt's colleagues was Lewis G. Weeks, now senior research geologist for the Standard Oil Company (New Jersey) and presently distinguished lecturer of the American Association of Petroleum Geologists, on "Sedimentary Basin Development." For more than 10 years, Weeks has carried on extensive geologic studies of the deposits, reservoirs, and possible sources of oil throughout the world leading to estimates of the ultimate production of oil in the United States

†Presented before the annual convention, *American Gas Association, Atlantic City, New Jersey, October 2, 1950.*

*Vice President, The Chase National Bank, New York, New York.

[1]Pratt, Wallace E., *"Oil in Earth,"* University of Kansas Press (1942).

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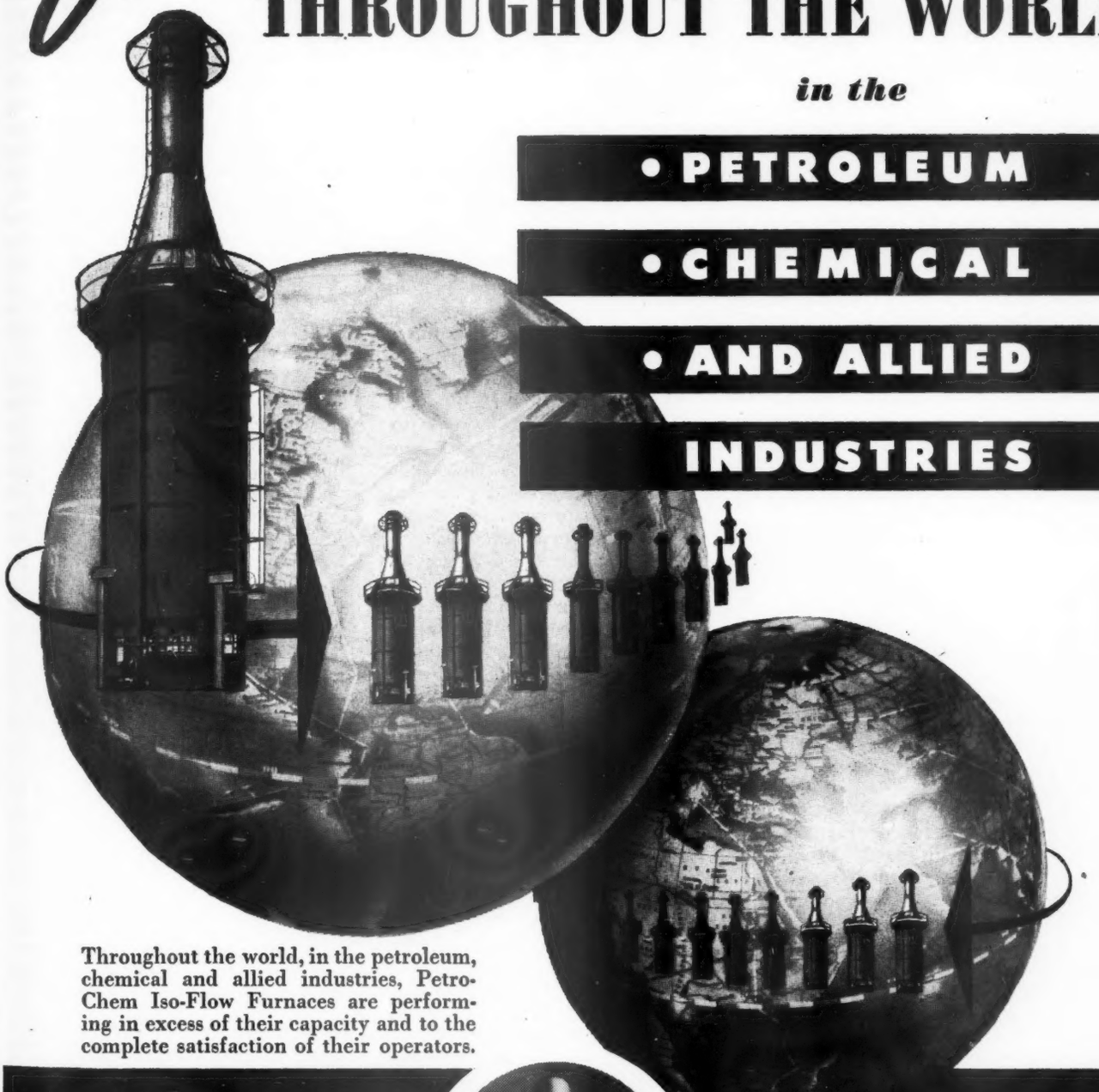

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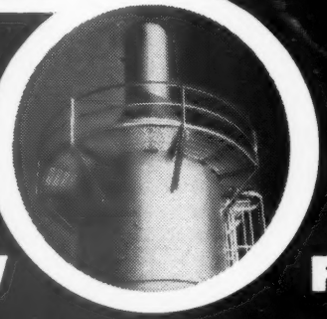

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TABLE 1. Past production and discoveries of gas and oil.

Total U.S.	Natural gas Trill. cuft	Crude oil Bill. bbl	Ratio Mcf/bbl
Produced to 1/1/50	160 (Approx.)	38.9	4.1
Proved reserves 1/1/50	180*	24.6‡	7.3
Discovered to 1/1/50	340	63.5	5.4

* By A.G.A. Committee on Natural Gas Reserves.
‡ By API Committee on Petroleum Reserves.

and other countries published by him in 1948.[2] A paper prepared by Weeks "Concerning Estimates of Potential Reserves" was published in the October, 1950, Bulletin of the AAPG.

The United States comprises an area of approximately 3,000,000 sq miles. Of this total, about 1,500,000 sq miles, having a volume of 2,000,000 cu miles, consist of sedimentary formations believed capable of having been source beds for the formation and accumulation of oil and natural gas. Oil and gas deposits of different origin, size, and character occur in various placements among the sedimentary basins of the earth. Weeks has given a great deal of thought to the development of yardsticks to be used in comparing or rating areas of potential production and to methods for estimating potential reserves. His methods are based upon the occurrence of oil in relation to the geology of fields and potential fields in the sedimentary basins. He has compared the known fields in relation to sedimentary basins in which they are found, area by area, with the outlying basins that are considered searching ground for new fields throughout the world.

From the extensive studies by Weeks, he has concluded that the crude oil reserves ultimately to be produced in continental United States, excluding tidelands, from formations down to 20,000 ft in depth should approximate 110 billion barrels. Total production had been 38.9 billion barrels to January 1, 1950, when 24.6 billion barrels were estimated to be proved by the American Petroleum Institute Committee on Petroleum Reserves. Based on these premises, 46.5 billion barrels then remained as discoverable in the future.

The quantities of natural gas that have been produced will never be known since large, unmeasured quantities were blown into the air and wasted in the early days. There are good records by the Bureau of Mines of the natural gas marketed in the United States since 1905. So far as can be estimated, some 84 trillion cubic feet of natural gas has been marketed, about 30 trillion lost and wasted in the natural gas industry, and an enormous but unknown quantity of gas in solution with oil had been wasted in the production of oil, so that total gas produced to 1950 has approximated 150 to 175 trillion cubic feet. Past production and discoveries of natural gas and oil are compared in Table 1.

[2]Weeks, L. G., *"Highlights on 1947 Developments in Foreign Petroleum Fields,"* Bull. Amer. Assn. Pet. Geol., Vol. 32, (1948), pp. 1093-1160.

Potential Gas Reserves

There are reasons for believing that, of the hydrocarbons to be discovered in the future, the ratio of gas to oil will be higher than has occurred to date. Some of the reasons are:

1. The trend of drilling is to deeper and deeper zones so that reservoir pressures of future discoveries may be expected to be greater than in the past. As gas is compressed somewhat in proportion to pressure, the quantity, by weight, of gas contained in a cubic foot of pore space is greater with increased depth. For oil, the reverse is true, as after the oil cools upon reaching the surface and the solution gas is released, the volume of oil is less than it had been in the reservoir.

2. Deposits of oil found at great depths and under correspondingly high pressures contain larger proportions of gas in solution than oil in shallow reservoirs. Of present proved reserves of natural gas, 15 per cent consists of gas in solution in oil and this ratio is likely to increase.

3. A principal future hunting ground for natural gas will be the Gulf Coastal Plain and the tidelands offshore therefrom. It was found by Barton[3] and recently confirmed by Brooks[4] that the hydrocarbons encountered in the Tertiary formations of the Gulf exhibit progressive change in composition with greater geologic age and depth, the older and deeper oils being of lighter specific gravity and having larger percentages of lighter constituents. Brooks, who examined oils from 154 fields, shows this to have resulted from contact of the original heavy bitumens with the natural catalysts of the retaining rocks through long geologic time under reservoir temperatures that are higher with increasing depth. Hence, it is likely that the future discoveries in this area at greater depths will contain higher proportions of free gas, as the deeper the deposit, the higher the reservoir temperature and the greater the possibility for more complete transformation of the original oil in place with resulting increased formation of gas. From whatever the cause, the fact is that recent drilling of exploratory wells has resulted in increasing proportions of gas wells to oil wells discovered. See Table 3.

4. The ratio of 4.1 Mcf per barrel for gas to oil produced to date seems oddly low compared with 7.3 Mcf per barrel for presently known reserves. But in the old Appalachian fields where oil and gas have been produced for 90 years, wells were to shallow depths, gas in solution was relatively small and there were few purely gas producing fields. Hence, it is felt that the deeper drilling of the future will produce results nearer to the gas-oil ratio of the presently proved reserves.

Weeks concludes from geological studies that the crude oil to be discovered in the future will be 46.5 billion barrels for the continental United States, exclusive of tidelands. For the reasons mentioned, it is felt that the ratio of gas to oil to be found in the future will be at least 6 Mcf per barrel and probably more. At 6 Mcf per barrel assumed as a minimum ratio, multiplied by Weeks' 46.5 billion barrels, approximately 280 trillion cubic feet of gas are indicated to be discoverable in the future from the continental lands of the United States.

Oil and gas have been found in great abundance in the near-shore plains and marshes along the Gulf Coast of Louisiana and Texas. Offshore, the sea bottom of the continental shelf slopes very gently to seaward and along the Louisiana and southeastern Texas Coast the depth does not exceed 60 ft of water as far

[3]Barton, Donald C., *"Evolution of Gulf Coast Crude Oil,"* Bull. Amer. Assn. of Pet. Geol., Vol. 21, (1937) pp. 914-46.
[4]Brooks, Benjamin T., *"Active-Surface Catalysts in Formation of Petroleum,"* Bull. Amer. Assn. Pet. Geol., Vol. 33, (1949), pp. 1600-12.

TABLE 2. Former estimates of proved oil reserves for U. S.

Date — Former estimates of proved oil reserves — By		Produced since est. to 12/31/49	Estimated by API committee 12/31/49	New reserves found since former estimate	Ratio
	Billion barrels				
1/1/22 AAPG and USGS	5.00	33.04	24.65	52.69	10.5
1/1/25 API Com. of 11	5.32	31.03	24.65	50.36	9.5
1/1/38 API Res. Com.	15.51	18.97	24.65	28.11	1.8

Compare ratios:

	Proved reserves 12/31/49 excluding tidelands	Estimated future discoveries	Ratio of future to present est.
Crude oil	24.6 bill. bbl	46.5 bill. bbl	1.9
Natural gas	180 trill. cu ft	280 trill. cu ft	1.6

as 40 miles from shore. There are many oil and gas fields on the Mississippi River delta overlying the continental shelf and demonstrating the existence of oil and gas deposits in the shelf miles to seaward from the normal coastline. In the last three years, much drilling has occurred in these tidelands and to date 12 oil fields and 12 gas fields have been discovered off the Louisiana Coast, some as far as 28 miles from shore. And a rich deposit of natural gas has recently been discovered in the Eugene Island block, 20 miles offshore from the Louisiana Coast where 500 ft of very porous gas bearing rocks have been encountered at a depth of 11,000 ft. The offshore wells, drilled from large steel derrick platforms built in the Gulf waters, are very expensive and, while numerous geologic structures have been discovered and await testing, there remain many problems as to the size, thickness and depth of the deposits and depth of water that will warrant development. The thickness of the possible oil and gas containing strata is enormous—it being more than 25,000 ft to the bottom of Tertiary formations that are the oil and gas bearing beds of the coastal area. The area of the continental shelf along the Gulf Coast from the Rio Grande to Alabama and within 60-ft depth line approximates 16,000 sq miles.

The potential gas reserve in these tidelands is of a very large order of magnitude, a quantity that cannot yet be approximated. But judging by the known reserves developed to date per 100 sq miles in the same geologic strata in the adjacent in-shore lands and the probable future potential thereof, the evidence from wells completed to date in the tidelands and the number of structures already found offshore, it is felt by the writer that the natural gas ultimately to be produced from the Gulf tidelands will exceed 50 trillion cubic feet.

From the foregoing reasoning, the minimum quantity of future supply that can be reasonably forecast may be summarized as:

United States	Trill. cu ft
Present proved reserves	180
Future discoveries: Lands	280
Tidelands	50
Total future supply	510

Former Estimates of Reserves

The reasonableness of the above forecast may be tested by reviewing the subsequent history of prior estimates of proved reserves. In 1921, following a wave of alarm over the apparently dwindling supply of oil, a committee of the AAPG, working jointly with the United States Geologi-

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TABLE 3. Projection of the trend of discoveries.

Year	No. of gas wells to oil wells[1] [2], ratio	Average depth of wildcats[1] [2], feet	Wildcats drilled[3]	New reserves found[3] Oil billion bbl per year	Oil billion bbl total	Gas trillion cuft per year	Gas trillion cuft total
			ACTUAL				
1938	.255	4,138	2,638	3.05	—	*	—
1939	.217	4,065	2,702	2.40	—		—
1940	.212	3,858	3,038	1.89	—		—
1941	.209	4,070	3,264	1.97	—		—
1942	.200	4,388	3,212	1.89	—		—
1943	.348	4,112	2,843	1.48	—		—
1944	.332	4,642	4,796	2.07	—		—
1945	.446	4,532	5,613	2.11	—		—
1946	.492	4,650	5,752	2.66	—	17.7	—
1947	.405	4,475	6,775	2.46	—	11.0	—
1948	.332	4,907	8,013	3.80	—	13.9	—
1949	.302	4,568	9,058	3.19	—	12.7	—
Average last 10 years				2.35			
Average last 3 years				3.15		12.5	
			ESTIMATED (U.S., excl. tideland)				
Next 10 years				2.00	20.0	11.0	110
2nd 10 years				1.30	13.0	7.5	75
3rd 10 years				.75	7.5	5.0	50
4th 10 years				.40	4.0	3.0	30
5th 10 years				.20	2.0	1.5	15
Total 50 years				—	46.5	—	280

[1] Of successful wildcats completed.
[2] Figures through 1949 by Reserve Committees of API and AGA.
[3] Lahee, F. H., Bull. Amer. Assn. Pet. Geol. Vol. 34, (1950), pp. 995-1013.

cal Survey, found 5 billion barrels of known oil reserves as of January 1, 1922. As indicated in Table 2, there have been 52 billion barrels of new oil reserves found since that time, a ratio of more than 10 of new oil found to the old estimate. The American Petroleum Institute created a famous Committee of Eleven in 1925 to study the problem and its findings were similarly small as judged by hindsight. Later the American Petroleum Institute organized its present Committee on Petroleum Reserves. The Committee's second annual report issued as of December 31, 1937, showed 15.5 billion barrels of known oil, since which time 28 billion barrels of new reserves have been found —a ratio of new oil to the old estimate of 1.8. Weeks' present estimate of reserves of oil to be discovered in the future of 46.5 billion barrels compared with the presently known reserves of 24.65 billion barrels is equivalent to a ratio of 1.9, which, in view of the experience following the 1987 estimate, seems reasonable enough.

The present AGA Committee on Natural Gas Reserves made its first report as of December 31, 1946, and former estimates by various organizations may not be comparable with those of the committee. There is a comparable estimate of the reserves of the Appalachian district, however, made by E. E. Roth as of December 31, 1934. Roth was then and is now chief geologist for the Columbia Gas System and its predecessor and since the organization of the AGA Committee he has been chairman of its subcommittee for the Appalachian district. His 1934 estimate (adjusted to include solution gas) was 6140 billion cubic feet. Since 1934 production for the district has been 5940 billion and the AGA Committee reports 4410 billion cubic feet of reserves as of December 31, 1949, indicating 4210 billion cubic feet of new gas found in the interim. Oil was discovered in the United States at Titusville, Pennsylvania, in 1859, so that by 1934 the Appalachian district had been producing for 75 years and it might have been thought that the search for oil and gas in that area had been practically completed. Even so, new reserves have subsequently been discovered in the area equivalent to 69 per cent of those known in 1934. Although the Appalachian fields have now been producing for 90 years, a number of large gas wells have been discovered this year in Clinton County, Pennsylvania, within 90 miles of the 1859 discovery, and total production of the Appalachian district today is still 77 per cent of the all-time high induced by the war demand in 1917. Over half of the known reserves of the United States as a whole have been found in the last 10 or 15 years.

The reasonableness of the foregoing estimates of future discoveries may also be tested by the projection of the trend of recent discoveries shown in Table 3.

The estimated futures in Table 3 follow patterns purposely designed to produce total future discoveries equivalent to Weeks' estimate for oil and that made hereinbefore for natural gas. Considering the long experience of growth of the oil industry, and the rate of new oil found in the last 12 years, it is felt that the decline in new oil to be found, as forecast by decades in Table 2, is reasonably rapid and that by this test Weeks' estimate of ultimate oil production seems quite conservative. Weeks himself feels that it is more likely that actual future production will ultimately exceed his estimates substantially than that it will be less. The pattern of discovery projected for natural gas also seems quite possible, and from this approach our estimate appears conservative—doubly so in view of its being based upon Weeks' very conservative estimate of future oil.

The writer discussed this problem of future supply in 1944[5] then venturing to estimate a future production of 300 trillion cubic feet *or more*. At that time, the highest estimate of proved gas reserves was 110 trillion cubic feet and production was about 4 trillion cubic feet per year. Since then, new pipe lines have been built, production has risen to 6.25 trillion cubic feet for 1949, new fields have been discovered and old fields enlarged, and great strides have been made in offshore drilling. Since 1944, too, the comprehensive system of estimating the nation's gas reserves inaugurated by the AGA Committee has revealed a higher level of proved reserves than formerly known. Thus, in the light of new evidence the 1944 estimate of future supply appears to have been entirely too conservative.

Conclusion

The proved reserves of natural gas are estimated with reasonable precision by the AGA Committee. But the total future supply, including the reserves yet to be discovered, cannot be accurately determined. If it can be shown, however, that the future supply will be not less than some minimum figure, such reckoning may be useful as a guide to management, consumers, and investors. More complete indications of the ultimate quantity of gas to be recoverable will be revealed in due time and provide a basis for revising any estimate made today. But from the present evidence, as reviewed above, it is my judgment that the future recoverable natural gas in this country will exceed 500 trillion cubic feet.

Acknowledgments

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[5] Terry, Lyon F., Proc., Nat. Gas Dept. Amer. Gas Assn., (1944), pp. 133-137.

Studies and Experiments With Paraffin Prevention and Removal in Wells in Southeastern Ohio†

John C. Wright*

THE term paraffin is given to the waxy residues from crude oils that are deposited in the tubing, casing, and on the walls of the producing oil and gas well bores. These paraffin accumulations have been a problem to oil operators since the early days of the oil industry.

There has been much research done on this problem, both preventive and alleviative measures; some quite successful and others failing entirely in their purpose.

Each oil field has its own peculiar characteristics and conditions, and similarly, individual wells, even adjoining each other, often have very different operating conditions. Hence a "paraffin treatment" that might work on one well or local area, may be entirely unsuccessful in another well or field.

Physical Nature of Paraffin

Briefly, the crystalline behavior and chemical composition of paraffin will be discussed. Some say that there are both crystalline and amorphous (noncrystalline) waxes found in paraffin, while others believe that the waxes found in paraffin are all crystalline; the crystalline development of some waxes having merely been retarded and altered by the crystallizing medium of oil and possibly by the presence of colloidal material.

The number of different compounds and types of waxes found in paraffin are dependent upon the character of the crude oil. These include crude oil, water, gums and resins, asphaltenes, sand, and silt.

It has been found that oil is mostly mechanically held in paraffin—that is, trapped between the wax grains. There is some oil actually in solution or absorbed by wax crystals, but the amount is small. The same is true for any type of water present in the paraffin.

A large amount of oil in paraffin tends to make it soft, semi-fluid, and more readily affected by heat, regardless of the melting point of the wax present. This is true because the oil dissolves and softens part of the wax when the temperature is increased. If very little oil is present in the paraffin, the paraffin is hard and less plastic; and an increase in temperature does not have much effect on plasticity until it approaches the melting point of the solid waxes present.

The gums and resins are normally reddish-brown unsaturated compounds in solution in the crude oil. Their presence in paraffin waxes is probably due partly to their absorption by the wax as it crystallizes from the solution, and also the result of decreased crude oil solubility due to temperature change and loss of lighter fractions. The gums and resins normally comprise about 10 to 15 per cent of paraffin.[1]

The asphaltene content in paraffin waxes is normally very small.

The melting points of paraffin waxes vary from 0 deg to approximately 200 F. The crystalline waxes have melting points up to 150 F, and the amorphous or possibly retarded crystalline developed waxes melt at 150 to 200 F. These paraffins dissolve each other to some extent and in a large volume of the base oil will dissolve and liquefy at about 130 F. The crude wax deposited in the well is composed chiefly of the higher melting waxes, and the amount of waxes of lower melting points and molecular weights present in wax depends on the extent to which the oil was cooled or evaporated while deposition took place.[2]

The paraffins found in wells in the same field will vary considerably in the amount of different melting point fractions of wax as the conditions causing their deposition vary with each individual well.

Causes of Paraffin Deposition and Accumulation

The mere fact that paraffin forms wax crystals and separates from solution in the oil is not sufficient in itself to cause the accumulation of paraffin. In a great many wells paraffin separates from solution in the oil and flows or is pumped with the oil out of the well, never accumulating in the tubing or on the sand face.

The separated material was originally in solution in the oil, but certain conditions upset this equilibrium, so that the oil could no longer hold these waxes in solution; hence separation and possibly deposition occurred.

There have been many reasons and theories advanced for the separation and following deposition of paraffin from crude in oil wells. Those that follow seem most plausible to the author:

(1) Temperature seems to be the most important single factor involved, since the amount of paraffin an oil can hold is dependent upon the temperature up to saturation.
(2) Losses of the lighter fractions of the crude oil.
(3) Transfer of heat from the crude oil to the pipe and subsequently to the adjoining formations.
(4) Alternate draining and coating of the sand and tubing.
(5) Presence of foreign particles to provide nuclei for paraffin formation.

As the temperature is lowered in the crude its ability to hold paraffin is decreased. The greatest pressure drop, whether in a new or old well, occurs at the well bore. Hence the pressure drop is accompanied by a temperature drop, its degree dependent upon the amount of gas present in the reservoir that has an opportunity to expand. An expanding gas that is doing work in pushing the oil to the well bore will cause a decrease in temperature. The pore spaces of the sand at the well bore act as orifices and appreciable cooling at the face of the sand may occur when a high differential pressure between the formation and well bore exists. Here the thermal energy of the gas is consumed in increasing the velocity or density of the gas or both. If the temperature drop is sufficient, the separation of paraffin will occur at the sand face.

Low temperature points in the tubing may occur where the pressure of the expanding gas becomes greater than the partial hydrostatic pressure in the tubing or casing, and the gas breaks through the oil causing cooling at that point. This often happens when the gas-oil ratio is increasing and refers to flowing wells, not to settled pumpers.

In natural flowing wells and gas-lift wells the evaporation of the light, more volatile fractions reduces the amount of wax an oil can hold at a definite temperature. Here conditions are continually taking place to reach an equilibrium point where the partial pressure of the liquid constituents will equal the vapor pressure. The loss of these lighter fractions results in the reduction in the volume of oil with no appreciable loss in paraffin content.

†Presented at the Spring Meeting, Eastern District, API Division of Production, Columbus, Ohio, April 3, 4, 5, 1951.

*The Wiser Oil Company, Sistersville, West Virginia.

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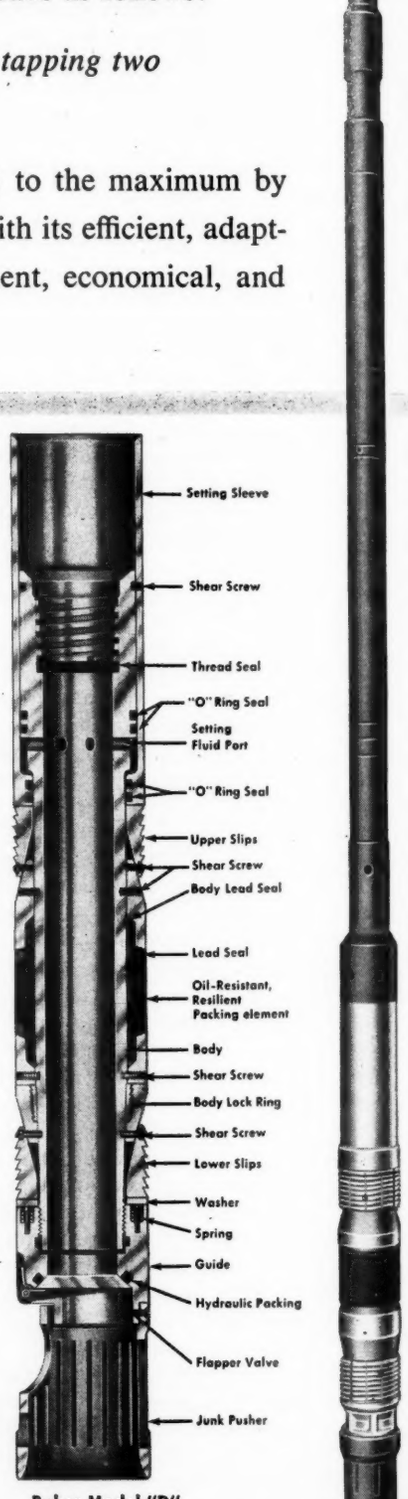

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The solubility of the paraffin is also decreased as paraffin waxes are more soluble in the lighter fractions of crude oil.[3]

Apparently the rate of cooling has little effect on the size of the particles formed. If the oil is agitated or if it is not cooled sufficiently to throw out enough wax to become solid, the small wax crystals agglomerate into particles or grains about the size of table salt. They later coagulate to form larger grains.[4]

For old wells that are pumped at regular intervals, the deposition and accumulation of paraffin is often due to cooling caused by the radiation of heat from the oil to the surrounding formation. If the oil is moving very slowly or stands in the tubing for a period of time, it will slowly approach the temperature of the surrounding formations. This temperature may be low enough for paraffin to come out of solution in the oil.

The intermittent coating and draining of the tubing is one of the most important causes of paraffin accumulation. In "head-wells" there is a constant coating and draining of the pipe surface. The oil in such wells is being lifted and dropped alternately until enough is accumulated to unload and flow. This leaves a film of oil on the tubing and an adhesive surface for the paraffin particles to accumulate upon. This slowly builds up as the oil leaves more paraffin until the tubing may become completely clogged. This same case is true with an old settled pumper, although it may take a longer period to build up the accumulation.

A well that needs only agitating by the sucker rods, similar to a "head-well," for it to unload the tubing for a thousand feet or more, often causes much trouble.

Aerated flow, where the oil is broken up into a mist by the gas, sometimes causes an oil film to accumulate on the pipe. If this flow is not thick enough to hold the wax particles in suspension, the particles will come in contact with the pipe and attach to it due to their soft gummy nature.

In viewing the general methods used throughout the United States with the idea of their possible application and use in Ohio, the marginal basis upon which the Ohio industry operates must be kept in mind. Ohio produced 3,485,000 bbl of oil in 1949 as compared to 3,906,000 bbl in 1948 from 20,000 wells.[5] There are many magi-nal producing wells in Ohio that are pumped once or twice a week and make 5 to 10 bbl a month. The average producing well in Ohio made about .4 bbl a day in 1949 as compared to the United States average of 12 bbl a day.[6]

With these facts in mind it can readily be seen that a great many of the methods used in other areas of the country, where there is greater production, would not be economically feasible in this state.

Many pumpers and some operators are of the opinion that the wire line tends to help keep the tubing clear of paraffin due to its flexibility in pumping. It is the author's opinion that the wire line does very little good in this respect as there is a very small area for the line to slap in and the fluid in the hole has a damping effect on the line. As most wire line pump barrels use cups that must be replaced at various intervals, however, the pump cups act as a swab in cleaning the tubing of paraffin as the pump is pulled. In many cases this is sufficient to take care of the paraffin condition in older wells where the trouble is not severe.

Most operators are agreed that paraffin troubles are worse in the early life of oil and gas wells when the rock pressure is still high. This is probably due to the cooling caused by gas expansion at the sand face. In wells that begin to make some salt water, or make salt water at their inception, in most instances the paraffin trouble is alleviated a great deal or ceases to exist. This may be due to several reasons such as an increased velocity and volume of flow and/or the fact that the specific heat of water is about 50 per cent higher than that of oil, helping to keep the temperature up. Paraffin is generally found in the upper 2000 ft of tubing in the wells in Ohio.

Generally speaking, most operators use some method to keep the sand covered with fluid at all times. The two most common methods are the use of flood nipples, and merely hanging the tubing high enough so the well cannot be pumped down. By keeping the sand face covered it is believed that the solvent action of the oil keeps paraffin from plugging the sand pores. There is good indication that those operators who do not keep the fluid level up to the top of the sand do have more trouble with paraffin at the sand face. The indication is that when paraffin first visibly appears, it is accompanied by a loss in production far greater than the normal decline.

It is the author's opinion, after studying decline curves and the resulting large increase in production after application of bottom hole heating, that paraffin and possibly asphaltic material do clog the pores on the sand face, even when the sand face is covered with oil. In the latter case, however, it occurs a great deal slower due to the solvent action of the oil.

Many mechanical methods such as the paraffin knife, paraffin hook, corkscrew, "porcupine," swab, etc., have been or are being used in Ohio. From talking with operators, however, it appears that the use of mechanical tools, in general, is on the down grade. The more progressive operators believe that you have let the paraffin situation go too far when the need for mechanical tools arises. If the tubing is completely plugged, any one of these methods is usually a very slow process. Many operators wait to apply mechanical or other paraffin control methods until such time as the pump barrel and sinkers will not go to bottom after they have been pulled. The first step they normally follow when this occurs is to add more weight in the form of sinkers. If this does not work some mechanical method is often applied, such as a paraffin hook or knife to cut the accumulation out of the tubing.

Heat Application Methods

Some operators have burners under their oil tanks to heat their oil and put it back in the well. The normal procedure is to put the hot oil down the casing and shut the well in. This tends to warm the oil in the shot hole. One operator has used this method stating that he heats the oil to a temperature of about 90 F. It is the opinion of the author after observation and the running of experiments on the melting points of the various formation paraffins, that 90 F would be a very low temperature to accomplish much, particularly in view of the fact that this is about the temperature at the bottom of a 3000-ft well.

The use of steam in wells is practically non-existent due to the increased depth of wells and the fact that boilers are not readily available on leases today. Steam, however, is often used to clean out bad paraffin accumulations in tubing after the tubing has been pulled. Several supply companies in southeastern Ohio are equipped to handle the steaming operation, but this is costly as it not only involves the steaming operation itself, but also labor and haulage of the tubing. One operator has a small boiler that he carries on wheels behind a truck to the well location and steams the tubing there.

In many instances when paraffin has badly clogged the tubing and steam is not available, the tubing is pulled and laid on racks with one end slightly higher than the other. Gas is piped from the casinghead and a fire started under the tubing. Tubing can be easily ruined, however, if care is not used in applying this method.

The Dunn, Chalfant, and Mosser heaters find very little use in Ohio for the removal of paraffin due to the cost of application and the equipment necessary. The Dunn heaters have been used sporadically around Marietta

since their origin in 1939, and have been primarily limited to their usage to that local area. The two former types are resistance-type heaters while the latter is an open flame type heater.

Heat-Forming Chemicals

Nearly every operator talked with had used a heat-forming chemical at some time, usually in the form of calcium carbide. Generally speaking, while some success has been obtained from these methods, they have not given satisfying results and are used very little in southeastern Ohio. Operators have voiced several further objections to them, one being that as a result of their heating action, a small residue in the form of cinders is left in the well. This residue is damaging to the pump and cups. Also, in the case of calcium carbide, hazardous acetylene gas is formed.

Another reason it is not generally practical to use heat-forming chemicals to remove paraffin from the casing and tubing is that it is difficult to make the reaction take place in the tubing or casing and to melt the paraffin. If the reaction takes place in the bottom of the hole, for the purpose of melting paraffin deposits in the tubing or casing, most of the heat will be dissipated before it reaches the paraffin deposits in the oil string unless a very large quantity of chemicals is used.

One type of heat-forming chemical compound used in the Appalachian area is herein described. About 80 to 100 lb of dry chemicals are put down the annular space between the tubing and casing, followed by a quantity of water, the quantity depending upon the thickness of the oil sand and the amount of fluid in the hole. The chemical reaction between the water and chemical starts immediately, producing a heat that is maintained for some time to temperatures of approximately 120 F. Pumping is begun after about 3 hours of the chemical action and while the fluids are still hot. Treatment of the well by this method involves very little labor since the rods and tubing do not need pulling. This chemical compound is non-injurious to personnel and non-corrosive.

Solvents

Many solvents find use in Ohio. The "natural" solvents used are mostly crude derivatives such as naphtha, benzine, and casinghead gasoline. They are used either alone or in combination with commercial paraffin solvents.

There are five or more commercial paraffin solvents in general use in southeastern Ohio.

The schedule of application and the amount of solvent used is dependent entirely upon the condition of the well, and no set formula or statement can be made. The following examples will give some idea of what is done by operators in Ohio as to schedule and amount of solvent used.

One operator cuts 5 gal of solvent with an equal amount of gasoline and puts it down the tubing. The well is shut in and allowed to stand for about a day. The spent solvent, paraffin, and accumulated oil are then pumped out of the well. A "follow-up" application, using the same proportions of solvent, then occurs. This procedure takes place every 3 months on wells that have paraffin troubles.

Another operator puts 5 gal of solvent down the tubing, shuts the well in over the week-end, and pumps it out on Monday. This procedure is followed once a month.

Another operator uses one-half gallon of solvent cut with 5 gal of fresh oil, making this application once a week.

Fig. I shows a sketch of a re-circulation set-up. This is a fairly recent development and has been used by very few operators, but good results have been obtained.

Stripping jobs are quite the exception rather than the rule; however, they do occur occasionally. This is a situation where the paraffin is allowed to accumulate around the pump and rods in the tubing to such an extent that the pump is frozen in the tubing and cannot be pulled out. It is the opinion of the author that this occurrence is unnecessary, and caused in most cases by negligence or the lack of an adequate working force to look after the wells. The only time it could possibly be excusable, would be in the early life of the well, when the well characteristics are not yet well known or established. It is something, however, that does occur and must be reckoned with.

Salt

At first impression there appears to be little if any relationship between the accumulation of paraffin and the formation of salt in oil wells. If salt crystals accumulate in the tubing due either to casing leaks or formation water, a rough surface is formed upon which paraffin will more readily adhere, or vice versa. The accumulation of salt and paraffin where both are present is probably a simultaneous deposition in the tubing. This idea has been borne out by the results in several wells where the well has been washed with fresh water and paraffin has been pumped from the well after treatment. The fresh water probably dissolved the salt and the paraffin accumulation thereby loosened.

In one well where the tubing was clogged, a 1¾-in. sand pump was run in 2-in. tubing, and a combination salt-paraffin mass was recovered in the pump.

Hence it may be advisable if it is known that both paraffin and salt are present in the same well to first wash the well down with fresh water and watch it closely after treatment to see if it may loosen the paraffin, besides dissolving the salt.

Asphaltic Material

Most paraffin coming from wells is of a brownish color. It may be that the asphaltic particles present in the well stream, in which paraffin solidification is taking place due to its decreased solubility, could contribute to the precipitation of the paraffin itself by forming nuclei upon which crystallization builds.

It has been very difficult to give an explanation for the fact that one well will "paraffin up" more than another when both are operating under relatively identical conditions and coming from the same reservoir. The theory has been advanced that the asphaltic constituents may differ from well to well therein making different seed conditions for the crystallization process. This has not been proved, however.

The appearance of aphaltic deposits (bitumens) in oil wells and separators was first attributed to solubility effects, but later was shown to be re-

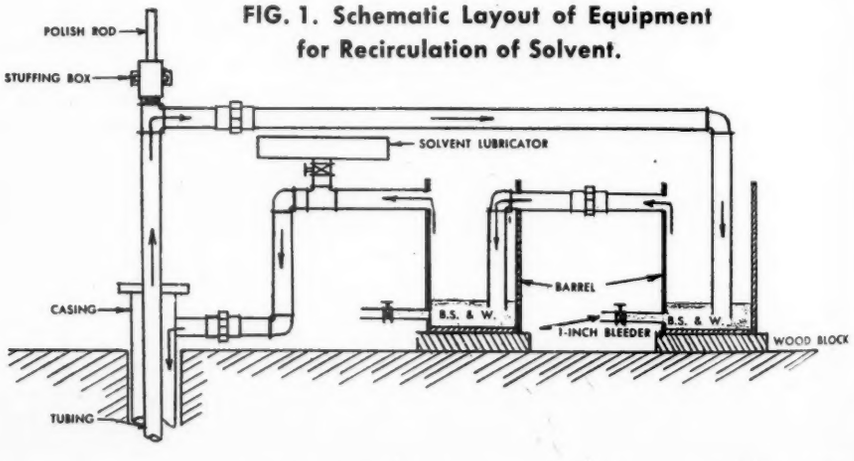


FIG. 1. Schematic Layout of Equipment for Recirculation of Solvent.

lated to electrokinetic effects.[7] The nature of asphaltic substances is not very well known, but they may be responsible for decreases in production in time. Work is now being conducted on this problem.

Carbonates

It has often been the case, as with salt, that where carbonate scale is present in wells there is also an excess of paraffin present. The combined accumulation quickly clogs the sand and tubing.

The carbonate scale may be treated by using dilute hydrochloric acid. This treatment may in turn loosen a lot of paraffin. It is suggested that this treatment be followed by some paraffin solvent to insure removal of the paraffin.

Depth-Temperature Relationships

In talking with various operators, an attempt was made to obtain bottom-hole temperature information on the Clinton and Medina sands. It was found that very few bottom-hole temperatures have ever been run in this area. One operator stated that the bottom-hole temperature of the Clinton ran from about 90 to 100 F in the few tests made. Another operator reported a Trenton well that had a bottom-hole temperature of 140 F at 6000 ft.

In reviewing the literature, it was found that few temperature surveys have been run in the whole Appalachian area. Fig. 2 shows an average depth-temperature relationship in Alleghany County, New York, and McKean, Tioga, and Venango counties, Pennsylvania.

Fig. 2 (8) also shows the results of depth-temperature observations in wells in 10 fields in West Virginia. The dashed curve shows the average relationship between depth and temperature measurements made in 5 wells in Cabin Creek, West Virginia.

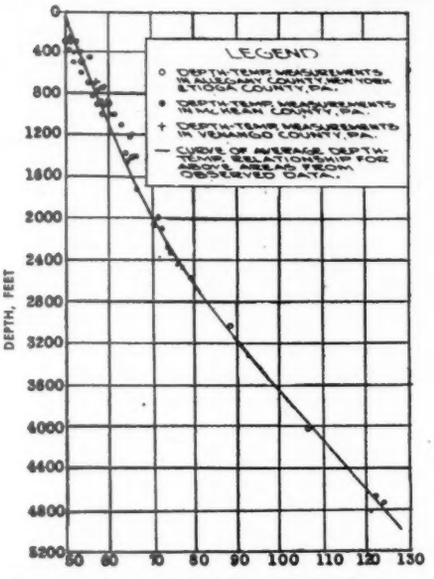
Hence, it can be seen from these two figures that at a depth of 3000 ft, the temperature is about 90 F in West Virginia, and about 87 F in New York.

It is not to be implied that these curves can be used to obtain subsurface temperatures in Ohio. The curves do give a general regional relationship, however, that may be applied with discrimination to this area, in view of the general lack of available information.

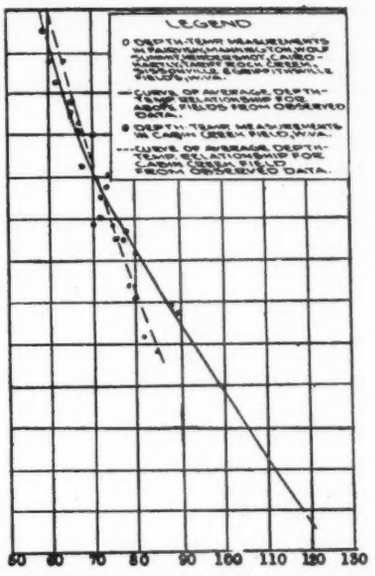
The Clinton sandstone, producing oil in Ohio, runs in depth from about 2600 to 4500 ft. The Maxton "300" sand runs about 750 ft around Marietta, Ohio where the paraffin sample was taken.

With all of the above information in mind, a series of experiments was run to obtain the various melting points of the different paraffins. These results are shown in Table 1.

FIG. 2. (After Tignor.)



Depth-temperature relationships observed in oil and gas wells in Allegany County, New York and Tioga, McKean, and Venango counties, Pennsylvania.



Depth-temperature relationships observed in oil and gas wells in West Virginia.

Samples of each type of paraffin weighing 2.5 gm were melted and the temperature at which all the paraffin was in solution was recorded. The average of five runs was taken.

Experiments

A series of experiments was conducted in the laboratory, the results leading to the following conclusions.

1. Heat greatly increases the solubility of all solvents for paraffin, particularly in the temperature range of 70 to 120 F. If heated solvents are to be used, however, care must be taken to see that they are non-inflammable.

2. Casinghead gasoline, naphtha, carbon tetrachloride, and carbon disulphide, when used in combination with each other, are not effective in dissolving paraffin. The initial breakdown and softening of the paraffin is fairly rapid, however. When these solvents are used in combination with commercial paraffin solvents, they seem to increase the latter's solubility for paraffin.

3. Certain combinations of solvents work much more rapidly than a concentration of any one commercial paraffin solvent by itself.

4. Crude paraffins coming from different sands, and different grades of oil in the same sand react differently to solvent applications. A change in well conditions may also change the paraffin constituency.

5. From a study of the bottom-hole depth-temperature relationship, and from the results of experiments on the melting points of the various paraffins, it can be seen that the temperature necessary to melt all the waxes in the paraffins are much higher than the probable bottom-hole temperature. This indicates the possibility that some of the wax and asphaltic material in the paraffin probably clogs the pores on the sand face slowly, even with the sand face covered with oil. In all probability this adds to the production decline.

From a study of the experimental data, it can be seen that certain solvent combinations are more effective than others in softening and dissolving paraffin, and that the addition of heat to a solvent or solvent combination greatly increases its solubility for paraffin. If a solvent or solvent combination is to be heated, however, a mixture must be chosen that is non-inflammable.

It was evident from the experiments that the commercial paraffin solvents seem to be more effective when cut

TABLE 1. Melting temperatures of various paraffins.

Formation	Run — degrees F 1 Deg.	2 Deg.	3 Deg.	4 Deg.	5 Deg.	Average
Zanesville-Clinton	148	142	153	143	158	148.8
Penna-Clinton	142	142	136	144	138	140.4
Medina	152	148	151	148	158	151.4
Maxton "300"	137	145	144	146	152	144.8
Corning*	150	166	153	162	164	161.0

* It is believed that the higher temperature from the Corning samples is due to a greater amount of foreign material within the paraffin samples.

Results;

The range of average melting points was from 140.4 F to 161.0 F

with some other solvent or solvents. Therefore, a savings in treatment cost can be made by following the procedure of cutting the commercial paraffin solvent with one or more other solvents.[a]

As an example, suppose that a 5 gal treatment was to be used. The average cost of a commercial paraffin solvent would run about $15. The cost of carbon disulfide or carbon tetrachloride is about $.75 per gallon. Hence, if 2½ gal of paraffin solvent was used with 2½ gal of carbon disulfide, the cost would be $9, a savings of $6 in one treatment. Most leases make some casinghead gasoline in the wintertime, hence if it were used, the cost would be further reduced.

To further substantiate the value savings by the regular use of solvents, some figures are quoted on the approximate cost of pulling the rods and tubing, and sending the tubing to a supply house for steaming. With the assumption that paraffin is in 500 ft of the tubing, the cost would run about $123, broken down as follows:

Assuming a 3000-ft well, it would take one day to pull the rods and tubing, and one day to re-run them:

$73.60	labor (four men @ $1.15 per hour for two days)
20.00	truck ($10 per day)
30.00	steaming @ $5 per hour (6 hours to steam 500 ft)
$123.60	

It can be seen that a substantial saving, with no loss in production, can be had by the regular use of solvents. Assuming that $15 worth of solvent is used every three months, the same amount of money would be spread over 2 years' time, as compared with a pulling job, with no trouble, loss of production, or wear on equipment. The cost of hiring out a crew of two men and a service unit would run about $144 for two days.

A satisfactory method of application, if a regular schedule is followed and the paraffin accumulation is kept at a minimum, is for the pumper to merely loosen the stuffing box and pour the solvent into the tubing. After letting it work for a period of time between regular pumping intervals the well is pumped off.

If there is a fairly large accumulation of paraffin in the well, a recirculation method may be used by connecting the flow line back into the casing. The setup as shown in Fig. 1 may be worth the time and trouble necessary to make it function. Most of the equipment necessary can be salvaged from around the pipe yard. Here salt, mud, water, and paraffin are caught by the barrels. The well first should be pumped down. If a non-inflammable solvent mixture was used, a fire could be built under the barrels and the solvent heated, but this is not advisable due to possible fire hazard.

As each well does have many characteristics peculiar only to itself, it is recommended that a somewhat similar procedure be followed as has been done in the experiments, on a less extensive basis. A sample of the paraffin should first be tested in various solvents and the solvent that gives the most complete removal used.

Most operators in Perry County are agreed that the secret of paraffin control is the treatment of their wells on a regular schedule, the schedule being dependent upon the condition of the well. The big trouble in the past (and still is with some operators) is that operators let their wells go until the tubing has become completely clogged, which then involved an expensive pulling and cleaning job and often a stripping job where the rods had to be cut.

According to supply companies located in southeastern Ohio, more and more solvent is being used to keep tubing and rods partially free from paraffin and to cleanse the sand face.

Application of solvent, following a regular schedule varying from 2 weeks to 6 months, has proved very successful. One operator following this procedure, reported that he had had no pulling jobs in over a year, due to paraffin conditions.

Many operators reported that solvent had been of little benefit or help to them. It is the author's belief that this is due, in many cases, either to lack of understanding of what solvents will do or misapplication of them. Some operators expect immediate results after pouring the solvent in the well. It is known that it takes a period of hours for the solvent to loosen and soften a paraffin accumulation so that it may be pumped out or flowed with the oil. Another common misconception of operators is that commercial paraffin solvent will penetrate several feet or more of paraffin-clogged tubing. Paraffin solvent will not break up a paraffin accumulation that has plugged tubing, but it can be used in conjunction with some sharp tool such as a paraffin knife that will cut through and introduce a fresh surface to the solvent. The solvent will work on the immediate surface, but will not penetrate very deeply.

A chemical field man cited an instance where a well had a 6-ft paraffin bridge in it. By using 20 gal of solvent with a paraffin knife, the accumulation was broken up in several hours.

The first step in deciding upon a method of treatment is to determine the type, amount, location, and condition of the paraffin in the well. When deposits have been built up over a period of months, they are usually hard and dense. In these cases the solvent procedure may require more time and more than one application of solvent. If the solvent is applied haphazardly without careful consideration or realization of the problems involved, the treatment may be considered a failure from the start. Success is possible when the problem is properly approached and application carefully planned.

Conclusions

1. There is no "sure-cure" for the prevention or control of paraffin accumulation and deposition.

2. Each well and each reservoir have their individual characteristics, and must be studied as such in regard to paraffin control.

3. It is the author's belief that asphaltic material in the oil is intimately tied up with the formation and accumulation of paraffin, and that further experimental work should be done on this.

4. The proper use of *cut commercial paraffin solvents* has proved successful and economical, and will continue to grow in importance in this area.

5. The secret of successful solvent application is the following of a regular schedule using the proper amount of solvent.

6. The use of plastic coated tubing to prevent paraffin deposition has been very successful in Louisiana. It may find future application in Ohio.

Acknowledgments

The author wishes to express his appreciation to the oil operators, pumpers, drillers, and roustabouts in southeastern Ohio who, in part, made this paper possible. Thanks also go to Professor E. V. O'Rourke of the petroleum engineering department, Ohio State University for his guidance and constructive criticism during the writing of this paper.

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[a]Commercial paraffin solvent means a solvent that is being marketed especially for the purpose of paraffin treatment. Other solvents include carbon disulphide, carbon tetrachloride, commercial naphtha, and casinghead gasoline.

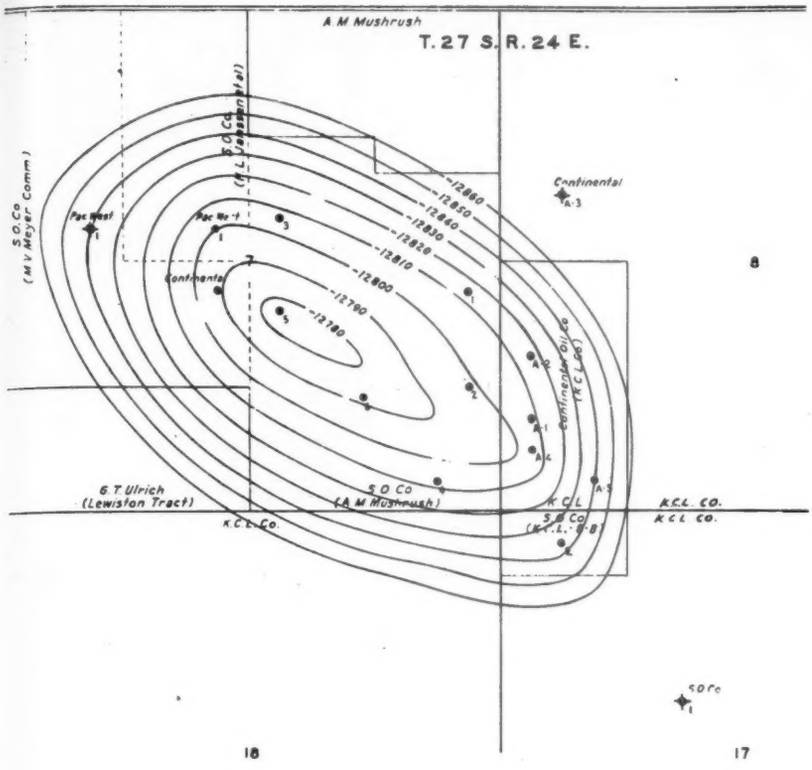

Plate 1. Vedder pool, Wasco oil field. Contours on top of A-2 sand.

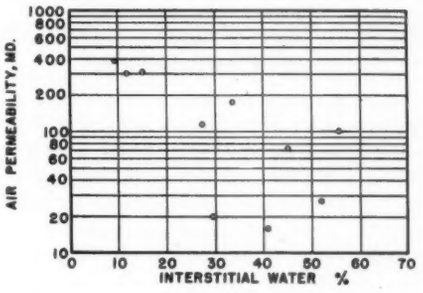

FIG. 1. Capillary interstitial water. Air displacement method. Sample from six wells.

Water Drive Reservoir Performance Vedder Pool, Wasco Field†

N. VAN WINGEN*

Abstract

This report summarizes a study of the Vedder pool in the Wasco field made by the Study Committee on Secondary Recovery of the API Pacific Coast District Committee on Production Practice. The investigation was undertaken to study the recovery efficiency resulting from a natural water drive in a California reservoir.

The Vedder Pool of the Wasco field is the first deep reservoir in California to approach economic depletion. The pool, which was discovered in 1938, comprises 500 acres. It has been subject to an active water drive to an extent that the current pressure is only 10 per cent less than the initial. As the oil was considerably undersaturated, the saturation pressure was not reached. The ultimate recovery factor is indicated to be 50 per cent of the tank oil initially in place, which is compatible with the recoveries obtained from water drive pools in other sections of the United States.

From a theoretical displacement efficiency standpoint, there is no essential difference between a natural and an artificial water drive mechanism. Accordingly, the fact that a California reservoir has shown a successful response to a natural water drive lends encouragement to artificial flooding prospects.

Introduction

The Wasco field is located in the San Joaquin Valley in Kern County, California, five miles west of Wasco in Township 27 South, Range 24 East. The field was discovered in 1938 as a result of seismic work. The discovery well, Continental Oil Company's KCLA-2, was drilled to the then world record depth of 15,004 feet, and, when plugged back and perforated from 13,092 to 13,175 ft, established a new world record production depth. The initial production rate was 3663 bbl per day of 35.7 API oil with a gas-oil ratio of 470 cu ft per barrel.

Geologic Data

The Wasco structure is an elongated dome, the longitudinal axis of which trends northwest and southeast. A map of the field showing contours on the top of the Vedder sand is shown on Plate I (below). The field had an initial productive area of 500 acres, and a closure of 85 ft. There is no evidence of faulting in the reser-

†Presented at the Spring Meeting, Pacific Coast District, Division of Production, American Petroleum Institute, Los Angeles, California, May 10 and 11, 1951.

*Petroleum Technologists, Inc., Montebello, California.

voir. Productive measures of the Vedder pool are of Lower Miocene age and are encountered at an average depth of 13,000 ft at Wasco. They are generally considered to be the equivalent of the Vedder zone found at Mount Poso, Rio Bravo, and other fields in this area. In September 1949 the Standard Oil Company deepened their well Mushrush No. 5 to 15,866 ft for a test of the Eocene sand. Although production was obtained at this depth, performance has not been sufficiently attractive to encourage an aggressive drilling program.

Reservoir Characteristics

Sand Characteristics. The Vedder formation at Wasco is a hard and well consolidated sandstone. Core analysis data are relatively meager. A total of 62 samples from four wells were analyzed for porosity and permeability, for 11 of which interstitial water determinations were also made by the capillary (air displacement) method (see Fig. 1). On the basis of these data, the average porosity and permeability are 15.4 per cent and 278 md., respectively. The above permeability was computed on the basis of an arithmetic average of the available data. An average permeability of 1500 md. is obtained if the average specific productivity index, as determined by depth pressure measurements, is converted to an equivalent laboratory permeability on the basis of the Johnston-Sherborne empirical correlation for California fields.[1] This discrepancy is not surprising in view of the small number of samples which were core analyzed. It is felt that 1500 md. is more representative of true reservoir conditions.

Fluid Characteristics. The capillary interstitial water curve (Fig. 1) indicates that the original value of the interstitial water content is somewhat less than 10 per cent for an average permeability value of 1500 md., and 15 per cent for 278 md. As this range is rather wide it was attempted to establish an interstitial water value on the basis of an interpretation of electric logs. The deep lateral and the self potential curves indicate that the Vedder sand is not clean, and in several of the logs a strong indication of the presence of a thin shale body is found which may separate the sand into two parts. Thus, a quantitative evaluation of interstitial water by means of the Archie formula[2] will not be accurate, as the latter is applicable only to clean sands. Accordingly interstitial water values ranging from 37 to 48 per cent, as computed by the Archie formula, are not considered to be reliable. It is evident from the preceding discussion that available data are inadequate to quantitatively indicate the original interstitial water value.

From a qualitative evaluation of all available information and analogy to other comparable reservoirs, however, it is believed to be 15 per cent.

The reservoir had an original pressure and temperature of 5660 psi and 277 F, as determined by subsurface surveys. A PVT study was made by the production technology laboratory of the Standard Oil Company of California in 1938 on oil and gas samples taken from Continental Oil Company's well KCLA-2. The following data were established for the original reservoir conditions: Formation volume factor, 1,244; solution gas-oil ratio, 390 cubic feet per barrel; and oil viscosity 0.55 cp. The oil was considerably undersaturated at initial conditions as the bubble point pressure is indicated to be 1480 psi.

Tank Oil in Place. A count of the productive sand in each well was made on the basis of a study of core data and the electric logs. On the basis of these data the isopachous sand map shown on Plate II was prepared. Data pertaining to markers and sand thicknesses are not available on the southwest flank as no wells were drilled in that portion of the field. Therefore the configuration of southwest contours is subject to interpretation. The isopachous map was planimetered and the total bulk sand volume was determined to be 11,730 acre feet, with an average sand thickness of 24 ft. Combining bulk volume data with the sand and fluid characteristics information, the total initial tank oil in place is 9,560,000 bbl (815 bbl per acre foot) and the original gas in place is 3,720,000 Mcf (see Table 1). These volumetric calculations are substantiated by water encroachment calculations, as discussed later in this report.

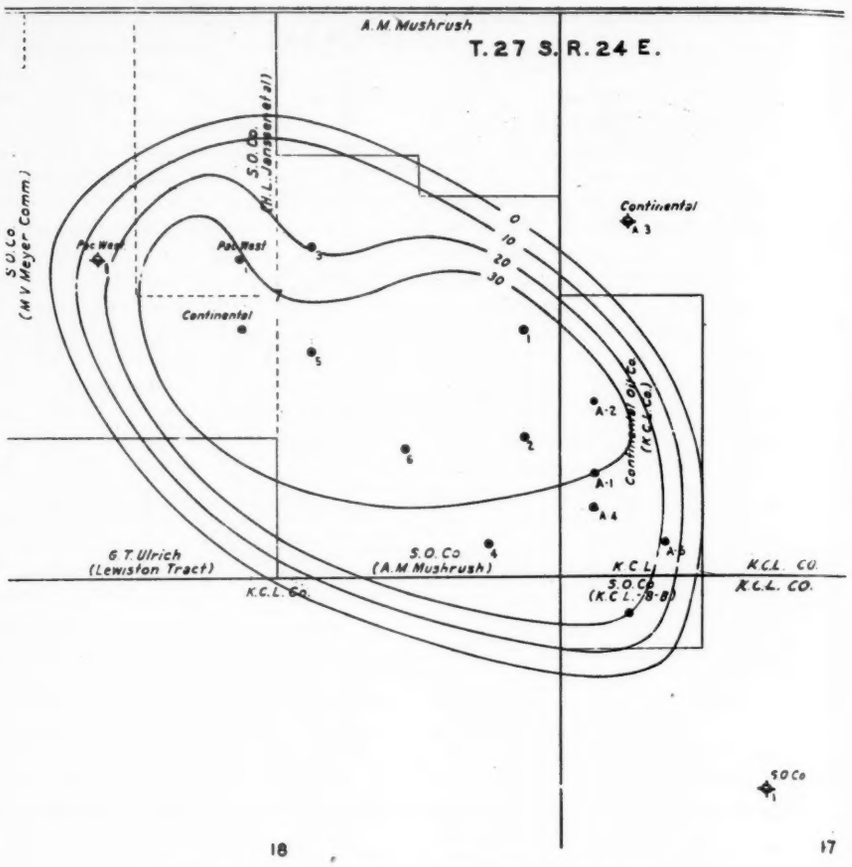

Plate 2. Isopachous map of productive A-2 sand. (Initial conditions.)

TABLE 1. Reservoir characteristics Vedder pool—Wasco field.

Sand characteristics	
Porosity	15.4%
Permeability	1500 md.*
Interstitial water	15%
*Specific productivity index data. Core analysis data indicate an average permeability of 278 md.	
Fluid characteristics	
Initial solution gas-oil ratio	390 C.F./bbl
Initial formation volume factor	1.244
Initial oil viscosity	0.55 cp.
Reservoir characteristics	
Initial reservoir pressure	5660 psi
Reservoir temperature	277 F
Initial productive acres	500
Initial productive acre-feet of sand	11,730
Initial average sand thickness	24 ft
Tank products initially in place	
Oil	9,560,000 bbl
Gas	3,720,000 mcf

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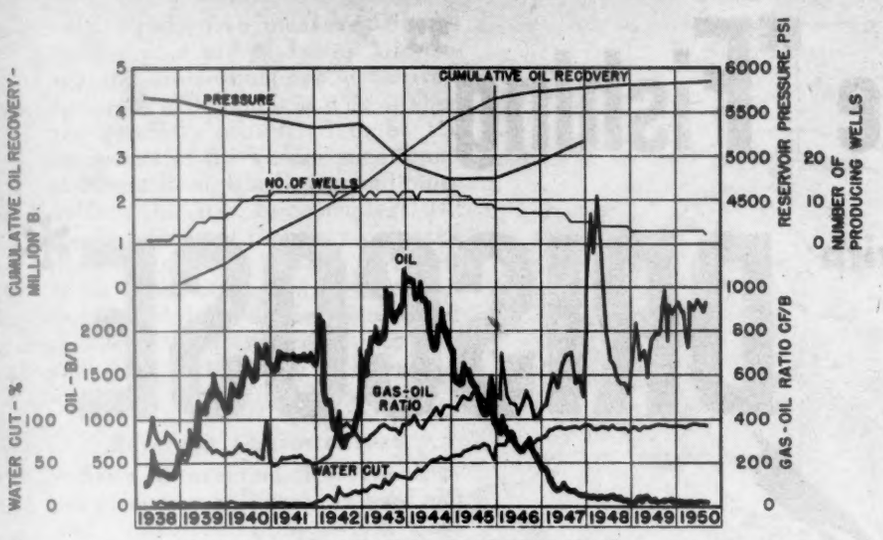

FIG. 2. Performance of Vedder pool, Wasco field.

TABLE 2. Production statistics, Vedder pool, Wasco field.

Date	Accumulative production W—M Oil million bbl	Gas million mcf	Water million bbl	Per cent cut at first of year	Reservoir pressure psi	Number wells producing
1-1-39	0.143	0.045	0.006	1	....	2
1-1-40	0.555	0.161	0.013	1	....	7
1-1-41	1.135	0.308	0.024	3	....	12
1-1-42	1.783	0.447	0.052	9	5335	12
1-1-43	2.214	0.576	0.134	19	5360	11
1-1-44	3.026	0.869	0.498	33	4915	12
1-1-45	3.822	1.200	1.353	59.2	4745	12
1-1-46	4.294	1.437	2.332	71.8	4745	8
1-1-47	4.552	1.558	3.164	82.3	4930	7
1-1-48	4.633	1.611	4.133	95.1	5175	5
1-1-49	4.678	1.652	4.585	92.7	....	3
1-1-50	4.706	1.674	4.992	94.8	....	3
Nov. 50	4.721	1.687	5.262	93.7	....	2

Estimated ultimate recovery — Oil 4,750,000 bbl (50 per cent recovery factor).

An attempt to determine the original tank oil in place by the material balance method of calculation was unsuccessful, principally because of the small amount of pressure decline during the life of the pool.

Reservoir Performance

Reservoir performance data for the Vedder zone in the Wasco field are summarized on Table 2 and Fig. 2. The curve trends are characteristic of those of a pool with an active water drive as exemplified by rapidly increasing cut, relatively low gas-oil ratio and slowly declining reservoir pressure. Except for a period of severe curtailment in 1942, the oil production rate exhibits the expected trend for this type of reservoir mechanism. Individual well histories follow trends similar to that of the entire pool. No secondary gas cap was formed because the pressure remained above the bubble point.

The pool had an initial period of approximately four years during which production was essentially clean and gas-oil ratios retained their initial values. It is of interest to note that the pool produced approximately 33 per cent of its indicated ultimate oil production during this period (16 per cent of the initial tank oil in place). Subsequently, the cut began to increase, a trend that continued until it reached approximately 90 per cent near the end of the pool's life, since which rise it has remained relatively constant.

The pool was capable of substantial oil production until the cut reached a value of approximately 50 per cent, after which time oil production fell off rapidly. Up to the point where rapid production decline set in, the pool had produced approximately 80 per cent of its ultimate oil production (39 per cent of the initial tank oil in place).

The gas-oil ratio declined from a value of approximately 350 cu ft per barrel to 200 cu ft per barrel during the first 4 years of production. (See Fig. 2.) Subsequently, the gas-oil ratio gradually increased to about 700 cu ft per barrel in 1948, seven years later. This behavior is interesting in view of the fact that subsurface operating pressures were substantially in excess of the saturation pressure. Several factors may have been responsible for departure of the gas-oil ratio from the saturation value of 390 cu ft per barrel. It is possible that the available data included only the gas taken from the separators. The ratio of the separator gas to the oil is affected by the pressure and temperature of the separator. Thus, the gas-oil ratios shown on Fig. 2 may have been af-

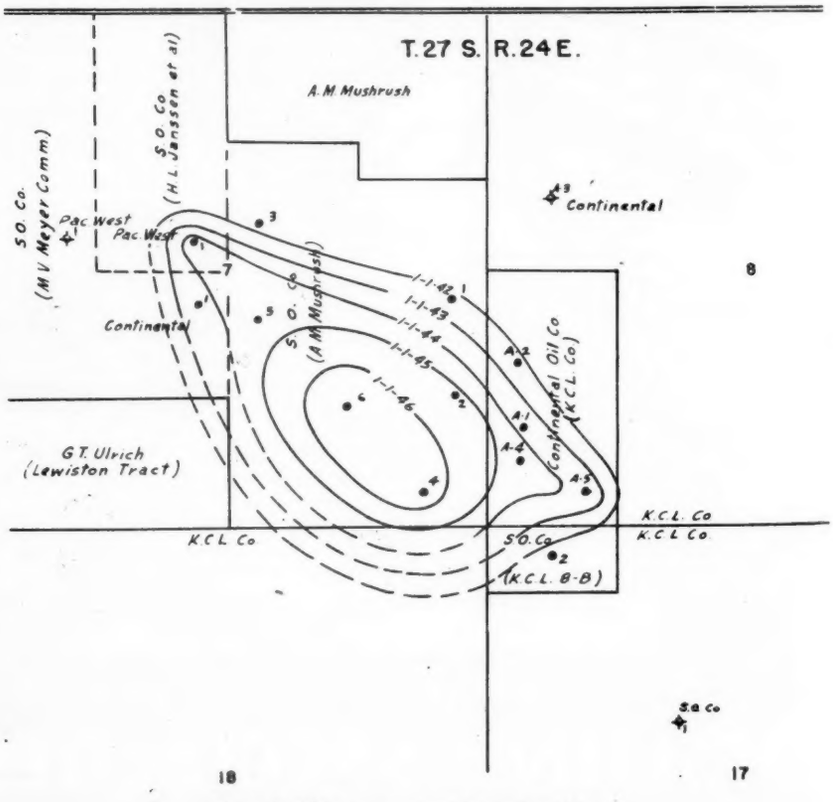

Plate 3. Water encroachment pattern.

Contours at 10 per cent cut.

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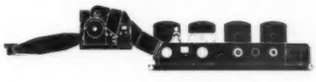

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fected by reductions in trap pressure and by increasing trap temperatures caused by greater production of water. This may help to explain the apparent simultaneous increase in water cut and gas-oil ratio that began in 1942, and which is apparent on both a pool and on an individual well basis. It is also to be considered that gas is soluble in water to a considerable extent, especially at the high pressures encountered in this pool, as reported by Dodson and Standing.[3] The actually observed increase in gas-oil ratio, however, is approximately twice that which can be so accounted for.

Water Encroachment

Plate 3 shows the position of 10 per cent cut lines at yearly intervals for the life of the pool. Ten per cent cut was chosen for this purpose because it gave the first definite indication that edge water had reached the individual wells. It is of interest to note that these lines are relatively smooth and uniform, and that their configuration conforms reasonably well with the structural contours of the Vedder sand.

By superimposing the 10 per cent cut lines on the isopachous map, total volumes of the reservoir flooded by water were calculated for successive time periods. These figures form a straight line when plotted versus the cumulative oil produced, as shown on Fig. 3. The slope of the line indicates a recovery of 410 bbl per acre-foot flooded, or about 50 per cent of the oil in place. The line extrapolates back to the origin, substantiating the sand volume used in this study and the magnitude of the overall recovery factor. This method would have disclosed any significant error in the previously estimated value of the bulk sand volume, since, in effect, it determines the reservoir volume existent beyond the outermost row of wells. The linear relationship observed on Fig. 3 indicates that the recovery efficiency was substantially constant throughout the reservoir.

An attempt to compute water encroachment by the Hurst method[4] was unsuccessful principally because of the very slight pressure decline occurring during the life of the pool.

Ultimate Recovery

As of January 1, 1951, the field had very nearly reached its economic limit and its production from the two remaining wells was only 45 bbl per day oil with an average water cut of 95 per cent, as compared to the peak production rate of 2720 bbl per day from 12 wells in December 1943. As of January 1, 1951, the field had produced a total of 4,722,000 bbl of oil. 1,688,000 Mcf of gas and 5,262,000

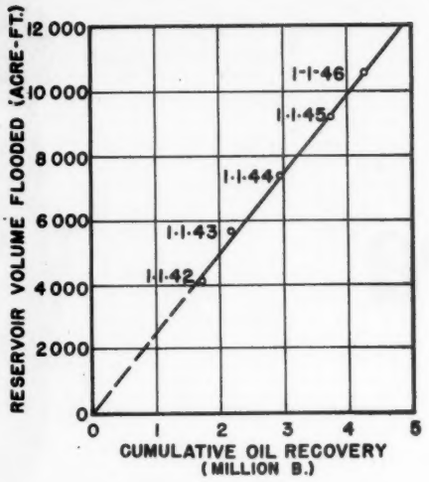

FIG. 3. Water encroachment vs cumulative oil recovery.

bbl of water. It is evident that very little future production is to be anticipated and, therefore, the ultimate oil recovery is estimated at 4,750,000 bbl.

The Vedder pool's average cut history as a function of accumulative production is depicted on Fig. 4. Extrapolation of this relationship to a reasonable ultimate maximum cut value substantiates the above indicated ultimate recovery figure.

On the basis of the above figures, the ultimate oil recovery is indicated to be 50 per cent of the initial tank oil in place (405 bbl per acre foot), and the gas recovery is equivalent to 45 per cent of the initial gas in place. It is to be noted that the recovery figure checks the 50 per cent value independently obtained by the water encroachment method of calculation.

The nonrecoverable oil left in the reservoir at economic depletion is equivalent to a remaining oil saturation of 42 per cent of the pore space, which is higher than that commonly observed in other areas of the United States. Muskat[5] lists 69 water drive reservoirs which show mean residual oil saturations ranging from 16-59 per cent and averaging 30 per cent. This difference is difficult to interpret because flooding test data are not available on Wasco cores. High residual oil saturation might be due, however, at least in part, to low original interstitial water saturation, possible error in this factor, the continuous non-existence of a free gas phase, and heterogeneity of permeability. An additional consideration is the fact that gross production rates averaged only 700 bbl per day with a maximum of 1500 bbl per day. The wells were pumped from a depth of 3000 to 5000 ft.

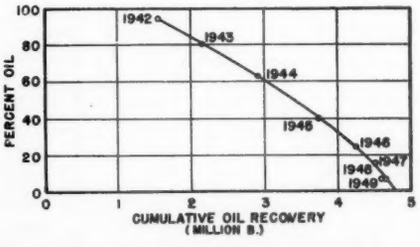

FIG. 4. Cumulative recovery vs per cent oil.

It is pointed out that the value of the original water saturation which was taken as 15 per cent, is of substantial importance to the magnitude of the recovery factor. As the original water saturation was not definitely established, the actual recovery factor might be in excess of the 50 per cent determined by this study, and the residual oil saturation correspondingly lower than 42 per cent.

Factors existent in the Vedder pool that have been favorable to high recovery include the relatively thin formation, the continuity of the reservoir, the apparently even advance of the encroaching water, and the low oil-water viscosity ratio.

The recovery factor of the 50 per cent is considerably higher than would have been expected in the absence of water drive. Muskat shows the mean recovery factory of 25 gas drive pools to be 33 per cent, which may be somewhat in excess of that obtained from many California reservoirs. Muskat also states that the mean recovery factor from 69 water drive pools is 52 per cent, which is in close agreement with the 50 per cent obtained from the Vedder pool.

From a theoretical displacement efficiency standpoint, there is no essential difference between a natural and an artificial water drive mechanism. Accordingly, the fact that a California reservoir has shown a successful response to a natural water drive lends encouragement to artificial flooding prospects.

Acknowledgment

The committee wishes to express its appreciation to the Standard Oil Company of California and the Continental Oil Company for generous contributions of data, without which this investigation would not have been possible.

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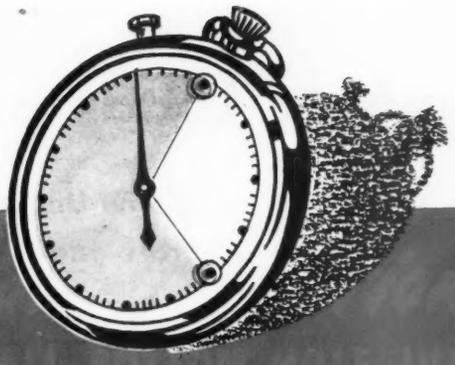
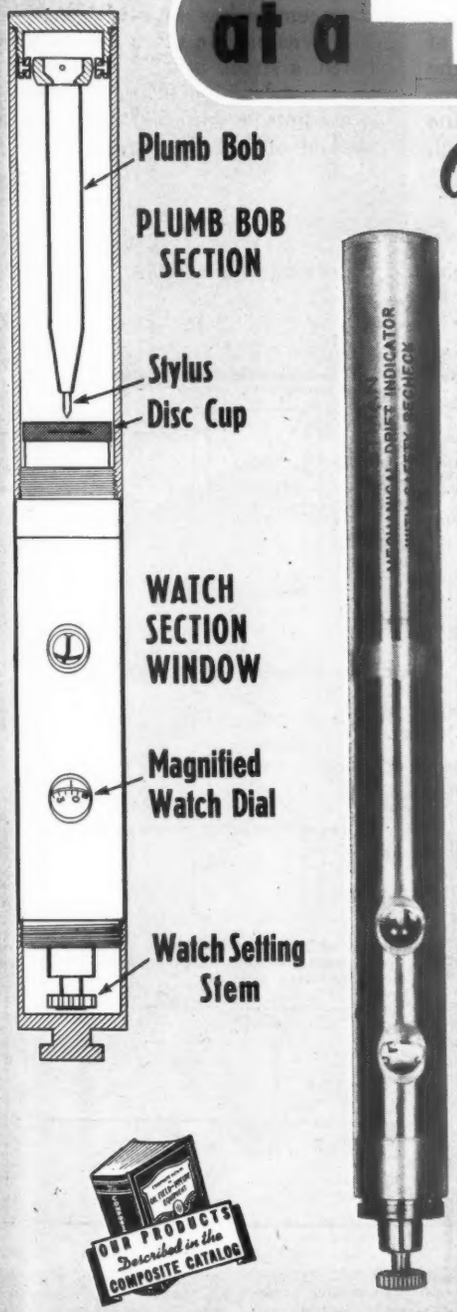
4. Hurst, W., "Water Influx into a Reservoir and its Application to the Equation of Volumetric Balance." Trans. AIME 1943.
5. Muskat, M., "Physical Principles of Oil Production." McGraw-Hill 1949. ★ ★ ★

2 READINGS at a 40 SECOND INTERVAL





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Allowable Loads on an Unsupported Casing

Column Under Action of Horizontal Wave Forces and Vertical Wellhead Loading

J. A. REED II* and H. H. MEREDITH, JR.*

Abstract

The completion of offshore oil and gas wells with conventional wellheads poses the problem of an unstable casing column. This paper presents a method for determining the allowed wellhead loading for such a column. A casing program is described and used in computations throughout the range of the investigation for normal water depths from 30 feet to 60 feet. Consideration is made of the horizontal forces acting on a round vertical column induced by the maximum probable breaking wave to be expected under hurricane conditions in the Gulf of Mexico at the design water depth with allowances for storm tide. The evaluation of these wave forces is discussed in the light of various theories which have been proposed.

A graphical method is shown for the determination of the stresses and deflections induced in a casing column by the wave force distribution computed from the theories accepted.

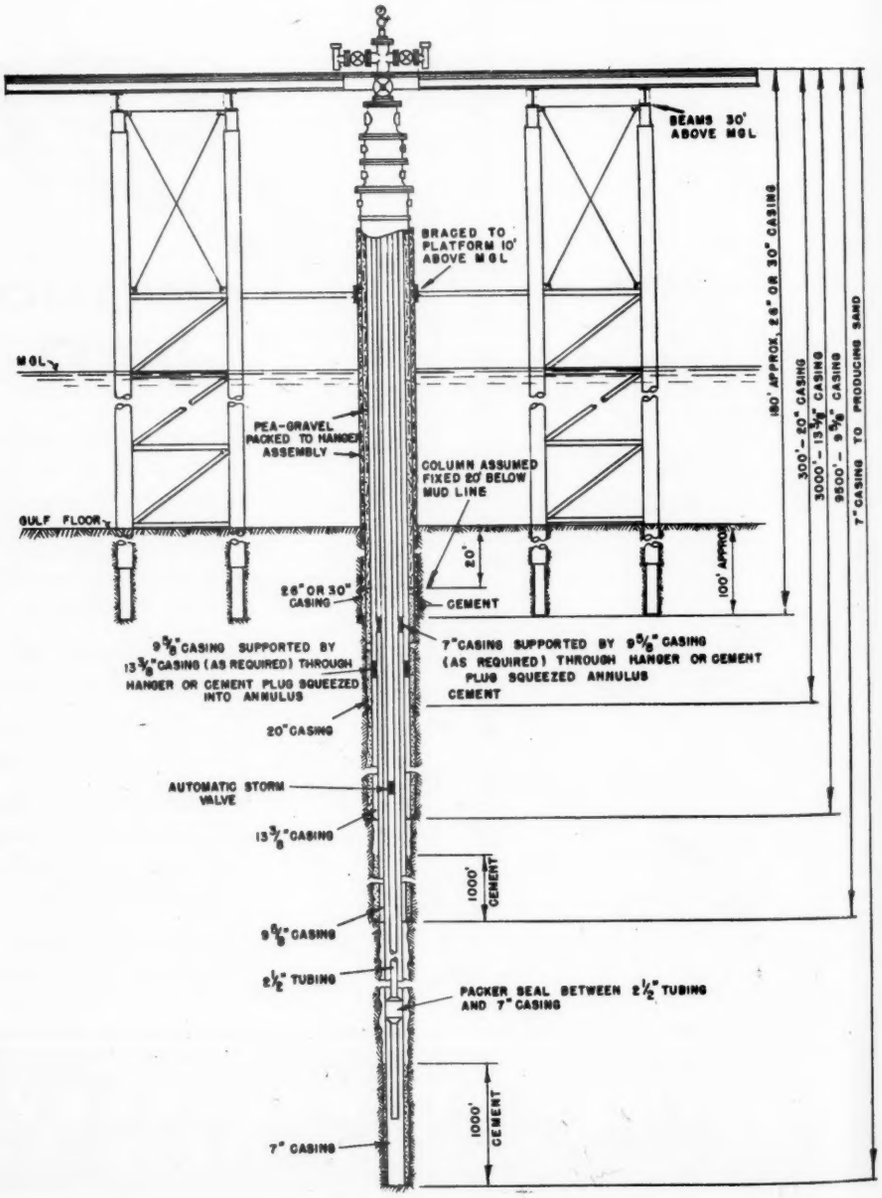
Introduction

Present practice in the completion of offshore oil and gas wells provides casing and tubing supension by conventional wellheads just under the platform that may be more than 100 ft above the highest lateral support below the mud line. The combined action of the vertical load from normal casing weights and the horizontal load from wave forces, produces a force system approaching or exceeding the ability of the column to withstand it. It is the object of this paper to present a method for determining the allowable wellhead loadings on offshore locations in water from 30 to 60 ft deep under conditions of maximum probable hurricane waves.

Design Conditions

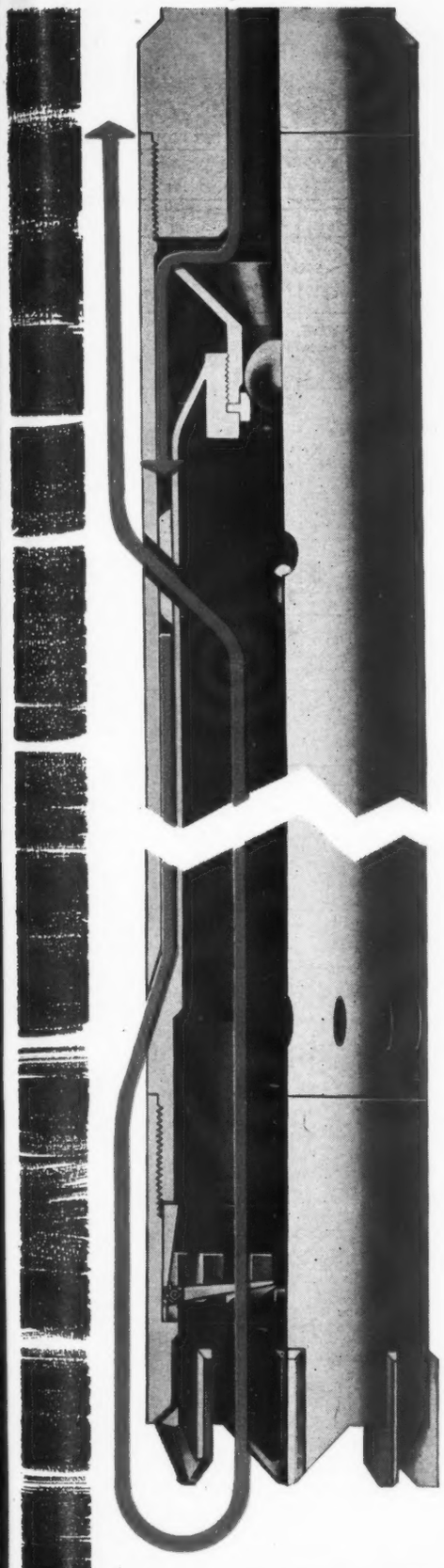
A casing program used by Humble is as illustrated in Fig. 1. First, 26-in. casing is driven and jetted to refusal to a depth of approximately 100 ft below the ocean floor. Second, a string of 20-in. casing approximately 300 ft in length is swung from the elevators and cemented to the top of the 26-in. casing, the cement in the annulus is washed out with small pipe to 20 ft below the ocean floor and the annulus packed with pea-sized gravel. The elevators are not released until after cement has set, which leaves the 26-in. casing in a stress free condition. Third, a string of 13⅜-in. casing approximately 3000 ft long is cemented at the bottom with 650 sacks and then slacked off to zero stress at the top

FIG. 1. Typical completed offshore oil or gas well.


BEAMS 30' ABOVE MSL
BRACED TO PLATFORM 10' ABOVE MSL
MSL
PEA-GRAVEL PACKED TO HANGER ASSEMBLY
COLUMN ASSUMED FIXED 20' BELOW MUD LINE
GULF FLOOR
20'
100' APPROX
26" OR 30" CASING
CEMENT
9⅝" CASING SUPPORTED BY 13⅜" CASING (AS REQUIRED) THROUGH HANGER OR CEMENT PLUG SQUEEZED INTO ANNULUS
7" CASING SUPPORTED BY 9⅝" CASING (AS REQUIRED) THROUGH HANGER OR CEMENT PLUG SQUEEZED ANNULUS
CEMENT
20" CASING
AUTOMATIC STORM VALVE
13⅜" CASING
1000' CEMENT
9⅝" CASING
2½" TUBING
PACKER SEAL BETWEEN 2½" TUBING AND 7" CASING
1000' CEMENT
7" CASING
180' APPROX. 26" OR 30" CASING
300'- 20" CASING
3000'- 13⅜" CASING
9500'- 9⅝" CASING
7" CASING TO PRODUCING SAND

†Presented at the Petroleum Mechanical Engineering Conference of The American Society of Mechanical Engineers, New Orleans, Louisiana, September 25-27, 1950.

*Humble Oil and Refining Company, Houston, Texas.



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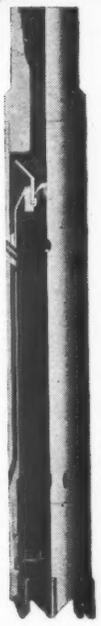

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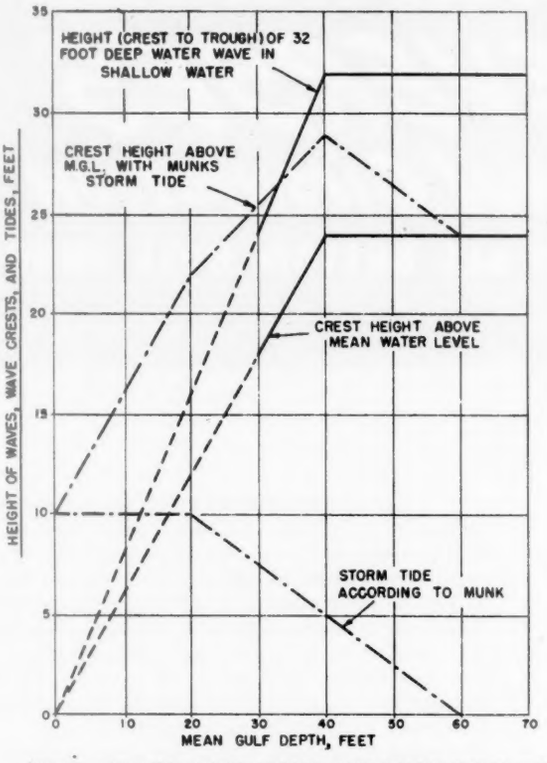
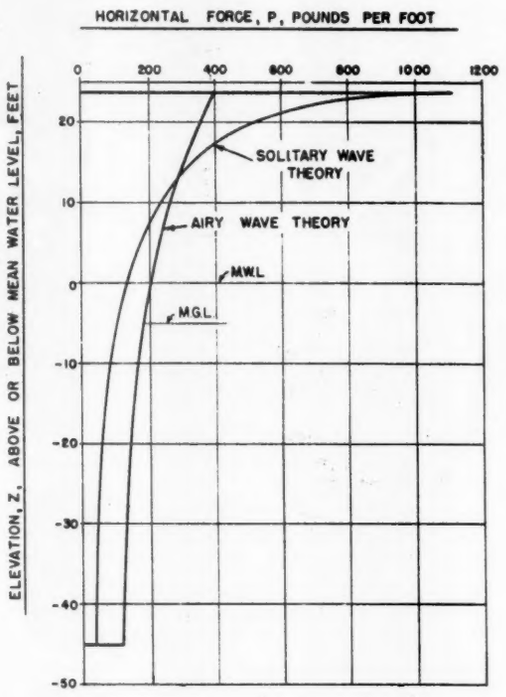

HEIGHT (CREST TO TROUGH) OF 32 FOOT DEEP WATER WAVE IN SHALLOW WATER
CREST HEIGHT ABOVE M.G.L. WITH MUNKS STORM TIDE
CREST HEIGHT ABOVE MEAN WATER LEVEL
STORM TIDE ACCORDING TO MUNK
HEIGHT OF WAVES, WAVE CRESTS, AND TIDES, FEET
MEAN GULF DEPTH, FEET

WAVE HEIGHTS, WAVE CRESTS AND STORM TIDES FOR 32' DEEP WATER WAVES BREAKING IN SHALLOW WATER

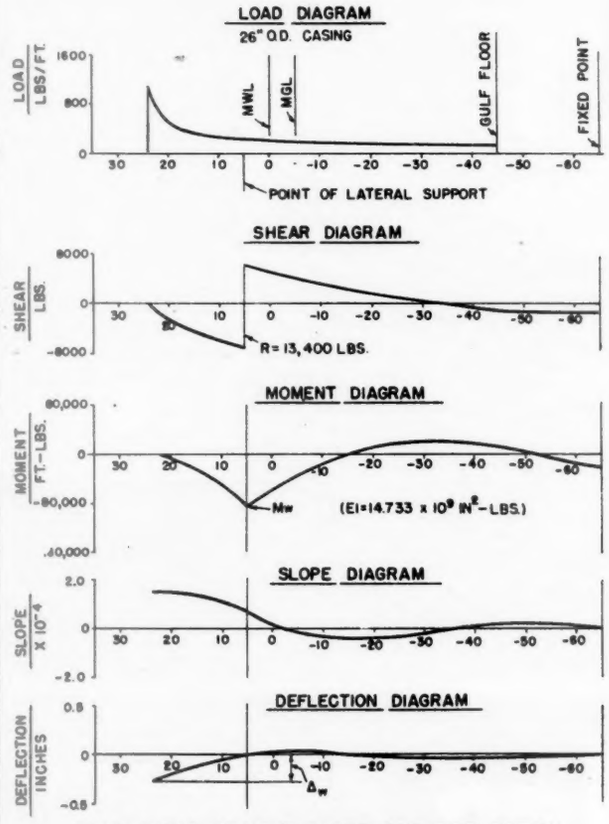
FIGURE No. 2



HORIZONTAL FORCE ALONG A 26-INCH CYLINDRICAL PILE

(32-FOOT BREAKING WAVE IN 40 FEET MEAN GULF DEPTH WITH 5 FOOT STORM TIDE)

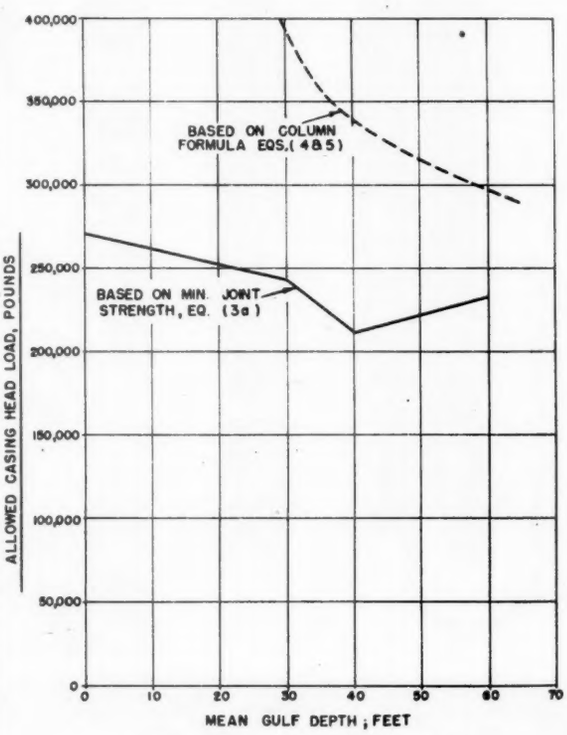
FIGURE No. 3



LOAD, SHEAR, MOMENT, SLOPE AND DEFLECTION

DIAGRAM FOR 40-FOOT MGD., 32-FOOT BREAKING WAVE, 5 FOOT STORM TIDE, AND CASING COLUMN AS PER FIG. No. 1

FIGURE No. 4

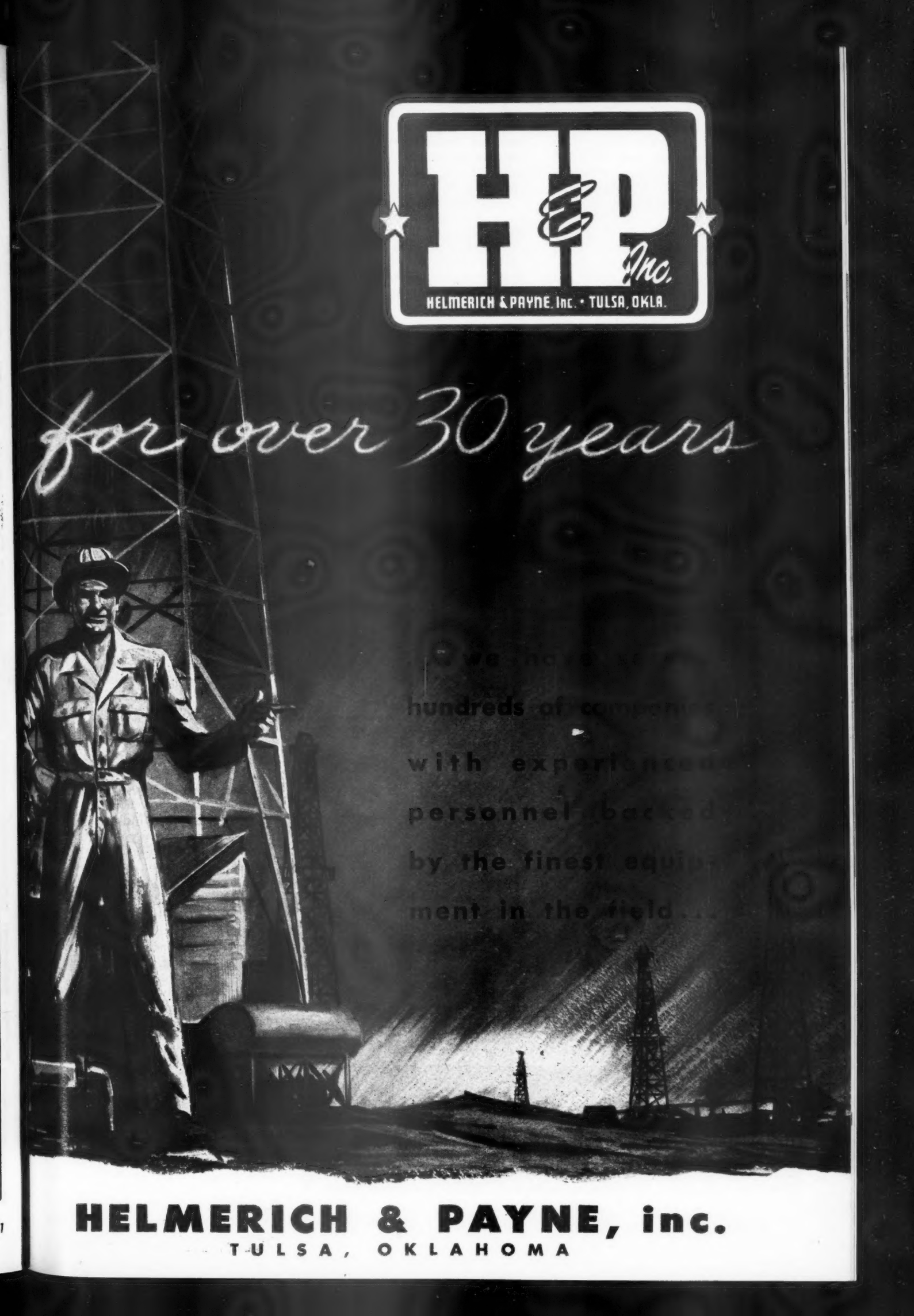


ALLOWED CASING HEAD LOAD

V_s

MEAN GULF DEPTH

FIGURE No. 5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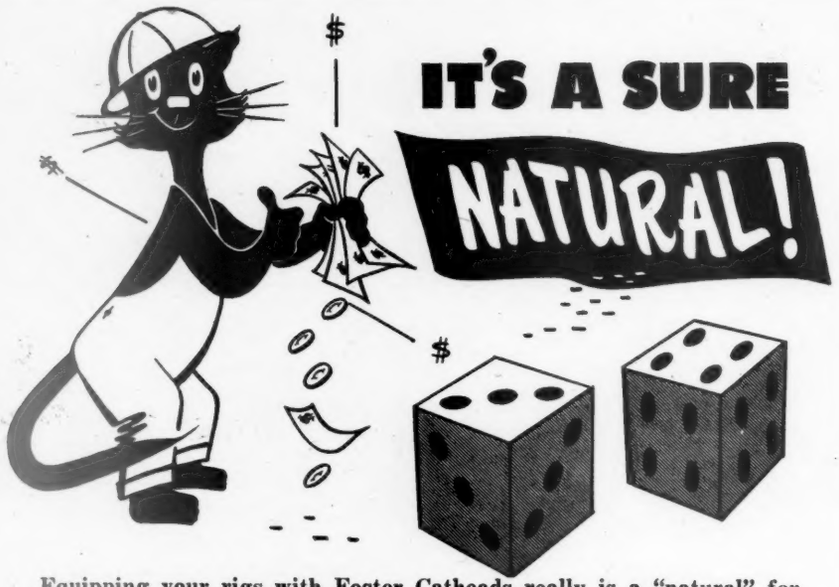
of the fixed portion as determined by pipe stretch after cement has set. The annulus between the 13⅜-in. and the 20-in. casing is then squeezed with 450 sacks of cement, which is displaced to 20 ft below the ocean floor. After this cement has set, the casing is slacked off to the residual load to be carried on the 20-in. by 13⅜-in. hanger. The annulus is then packed with pea-sized gravel from the top of the cement to the top of the annulus and the hanger set. Protector casing and oil strings are set with 1000 ft of cement at the bottom of each string. Secondary support is provided, if necessary, through a down-the-hole hanger or a cement plug squeezed through the annulus. These hangers or cement plugs are placed below the top of the cement sheath inside the 26-in. casing and above the casing seat for the 20-in. casing, and loads are thus transferred through the 13⅛-in. to the 20-in. casing to the formation. The residual load applied to the 20-in. by 13⅜ in. wellhead hanger is approximately 10,000 lb. All loads imposed by the inner strings smaller than 13⅜-in. are carried by the 20-in. casing. The whole assembly is laterally braced to the platform and zero deflection assumed at an elevation of 10 ft above Mean Gulf Level. As the ocean bottom in some parts of the Gulf is of a very fluid nature and offers little resistance to shear, the second point of fixity for the casing string is assumed to be 20 ft below the ocean floor.

The maximum probable deep water hurricane wave for the Gulf is estimated at 35 ft. Fig. 2 shows the height of breaking waves in various depths of water for a maximum wave height of 35 ft in deep water. For design purposes it has been assumed that in 60 ft to 40 ft of water, a 32-ft breaking wave will exist and in 30 ft of water, a 24-ft breaking wave. The height of all breaking waves is assumed to be ¾ above and ¼ below water level.

It has also been assumed that the effective water depth will be increased by a storm tide varying according to early estimates as shown in Fig. 2 from 10 ft at a normal water depth of 20 ft to negligible at 60 ft. The magnitude of storm tide has a substantial effect on allowed casinghead loads shown in Fig. 5 and also on the platform elevation required to clear a hurricane wave. Recent observations on two platforms approximately 8 miles from shore in 40 to 45 ft of water after the hurricane October 3, 1949, indicate that this storm tide estimate may be low, and has had a serious effect on platform and casinghead load design considerations. Humble is now assuming a 10-ft storm tide at all well sites and a 40-ft breaking wave in water depths greater than 40 ft in the design of future platforms.

The forces imposed by breaking waves have been predicted by several different theories. Munk has developed a conservative compromise employed by Humble, using the Solitary wave theory[1] modified by the Airy wave theory.[2] Maximum forces occur at the crest of breaking waves.

A plot of the horizontal force distribution, computed by Munk's theories, developed by a 32-ft breaking wave, along a 26-in. column in 40-ft normal water depth plus a 5-ft storm tide is shown in Fig. 3. The Airy wave theory gives greater forces than the Solitary wave theory from the ocean floor to a point above half way between Mean Water Level and the wave crest. Above that point the Solitary wave theory curve is greater. While the Airy and Solitary wave theories have been known for many years, neither has been positively validated for breaking waves. Therefore, in this investigation the theory is used that gives the greater unit force at any particular elevation.



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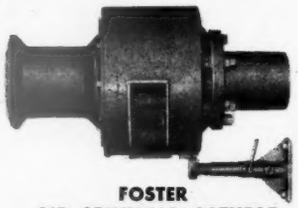

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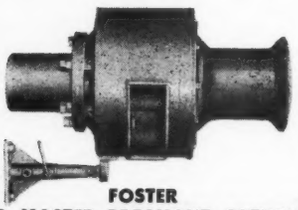

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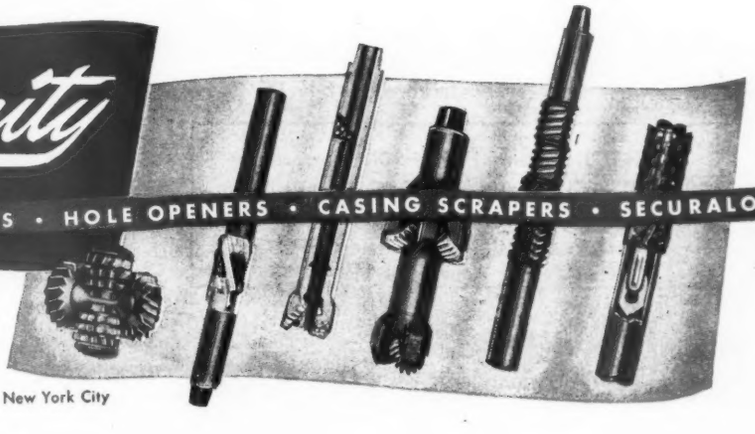

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Solution of the Problem

The casing column under the action of wave forces and as supported is a continuous beam with statically indeterminate stresses and therefore involves the theories of elasticity for solution of the reaction at the lateral support, the moment distribution, and the deflection curve. This was done by determining the deflection at the point of lateral support 10 ft above Mean Gulf Level as if that support were not there and then computing the lateral force required to reduce the deflection to zero at the point of lateral support. A graphical method was employed. The final result, showing the moment distribution and the deflection curve produced by wave forces for conditions at 40 ft Mean Gulf Depth is shown in Fig. 4.

Next the allowable axial load on the casinghead was determined from the following relation:

$$S_a = \frac{P}{A} + (P\Delta_t + M_w)\frac{c}{I} \quad (1)$$

where S_a is the allowable stress in pounds per square inch,
P is the allowable axial load in pounds applied at +29 ft,
A is the metal area of the 20-in. H-40 casing in square inches.
Δ_t is the maximum deflection with respect to the point of application of P, including the deflection due the axial load, inches,
M_w the maximum moment induced by the wave forces in inch-pounds,
c the radius to the outer fibers of the 20-in. H-40 casing in inches, and
I the combined moment of inertia of the three outer strings of casing in inches to the fourth power.

The allowable stress, S_a, for the 20-in. H-40, 94-lb casing is based on a minimum joint strength of 487,000 lb. Using a factor of safety of 1.8 and 26.9 sq in. cross sectional area. this pipe gives an allowable stress of 10,058 psi. The maximum deflection, Δ_t, is defined by the relation

$$\frac{P\Delta_t + M_w}{M_w}\Delta_w = \Delta_t \quad . \quad (2)$$

where Δ_w is the maximum deflection with respect to the point of application of the axial load, due to the wave loading only.

Relations (1) and (2) can be combined to give a quadratic expression

$$P^2 - P\left(AS_a + \frac{M_w}{\Delta_w}\right) + \frac{\left(M_w A\ S_a - \frac{M_w c}{I}\right)}{\Delta_w} = 0 \quad . \quad . \quad (3)$$

in which P is the only unknown.

Substituting for A, S_a, c and I gives

$$P^2 - P\left[26.9(10{,}058) + \frac{M_w}{\Delta_w}\right] + 26.9\frac{M_w}{\Delta_w}\left(10{,}058 - \frac{M_w}{491.1}\right) = 0 \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (3a)$$

The solution of (3a) requires that calculations be carried to five significant figures to develop a fair curve.

After determination of the allowable load by the preceding method, a check was made with a straight line column formula which gives the critical buckling stress for a column.[3]

$$S_a = 40{,}000 - 125\frac{l}{r} \quad . \quad (4)$$

in which l is the unsupported length of the column in inches, and
r is the radius of gyration of the column section in inches.

The allowable axial load based on the column formula is then determined from the relation

$$P = \left(\frac{S_a}{1.8} - \frac{M_w c}{I}\right)A \quad . \quad (5)$$

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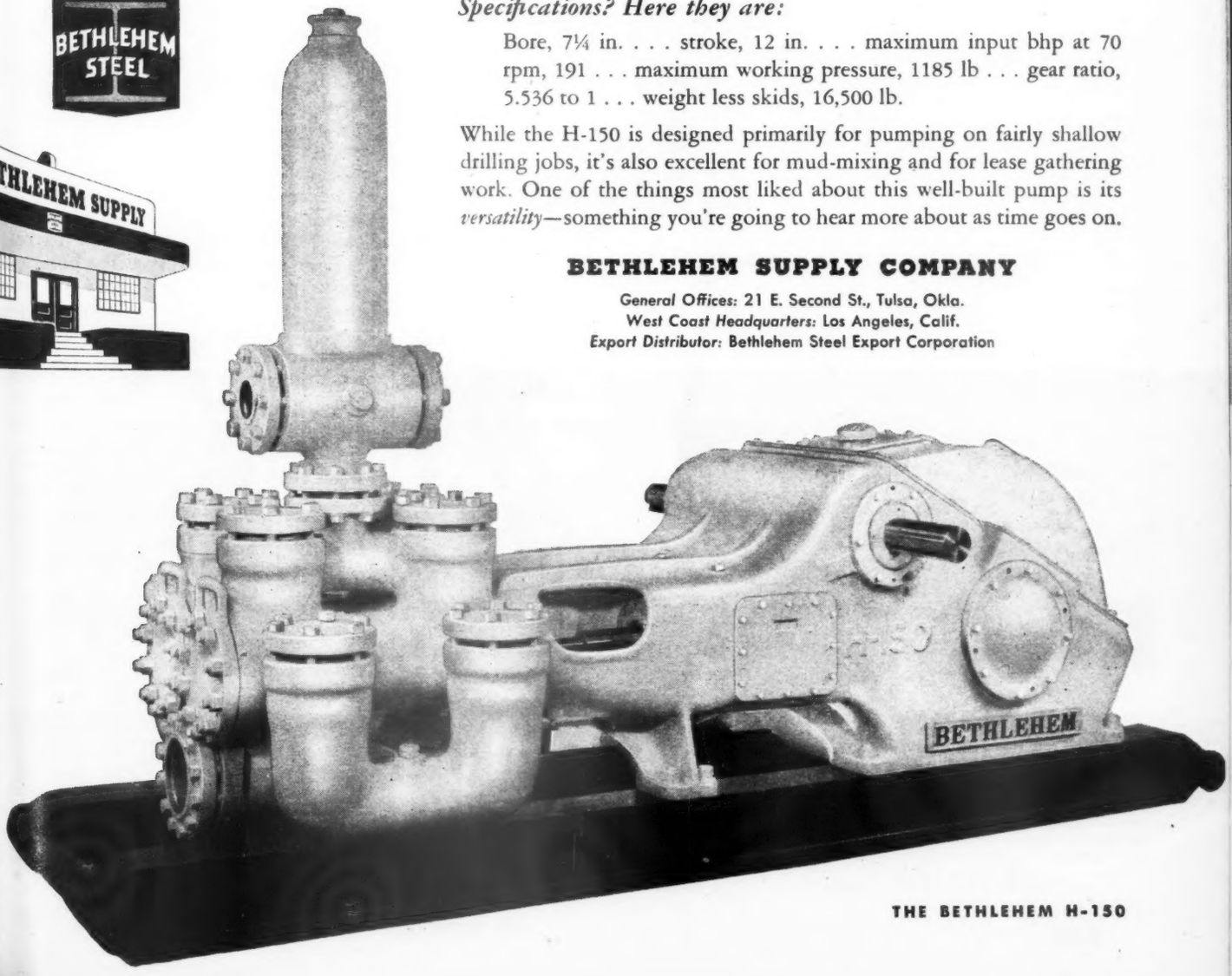

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The allowable axial loads as computed by relations (3a) and (5) were plotted against Mean Gulf Depth in Fig. 5. Allowable loads computed from relations (5) are higher than (3a) throughout the range of this investigation. It is recommended that the lower curve be used.

Discussion of the Solution

A new theory has been developed for the prediction of wave forces that indicates forces substantially greater than those predicted by Munk and used in the foregoing solution.[4] As the experiments from which the new equations were developed were performed with low Reynolds numbers and on only one size pile, ½ in., the results indicate the need for additional wave force research but do not justify abandonment of Munk's equations.

The assumed strength of the casing in solution (3a) is based on API minimum joint strength. The factor of safety of 1.8 usually applied in design of casing strings in tension is considered adequate because of satisfactory experience in completed wells, and is justified in comparison with higher factors used by the building industry because the major axial load is concentric and static.

The assumption of a fixed lateral support at 10 ft above Mean Gulf Level is justified because the change in stress at the lateral support where the stress is maximum is negligible even with a lateral movement of 6 in. Calculations have shown that a platform movement of more than 6 in., the estimated maximum under hurricane conditions, is required to develop a bending stress at the point of fixity below the Gulf floor greater than the stress at the platform support.

The original Grand Isle casing program on which this solution is based has been revised by substituting 30-in. for the 26-in. conductor pipe. This change increases the allowed casing-head load because the resistance to bending is proportional to the cube of the diameter while the wave force absorbed varies directly as the diameter. It also allows additional space for gravel packing.

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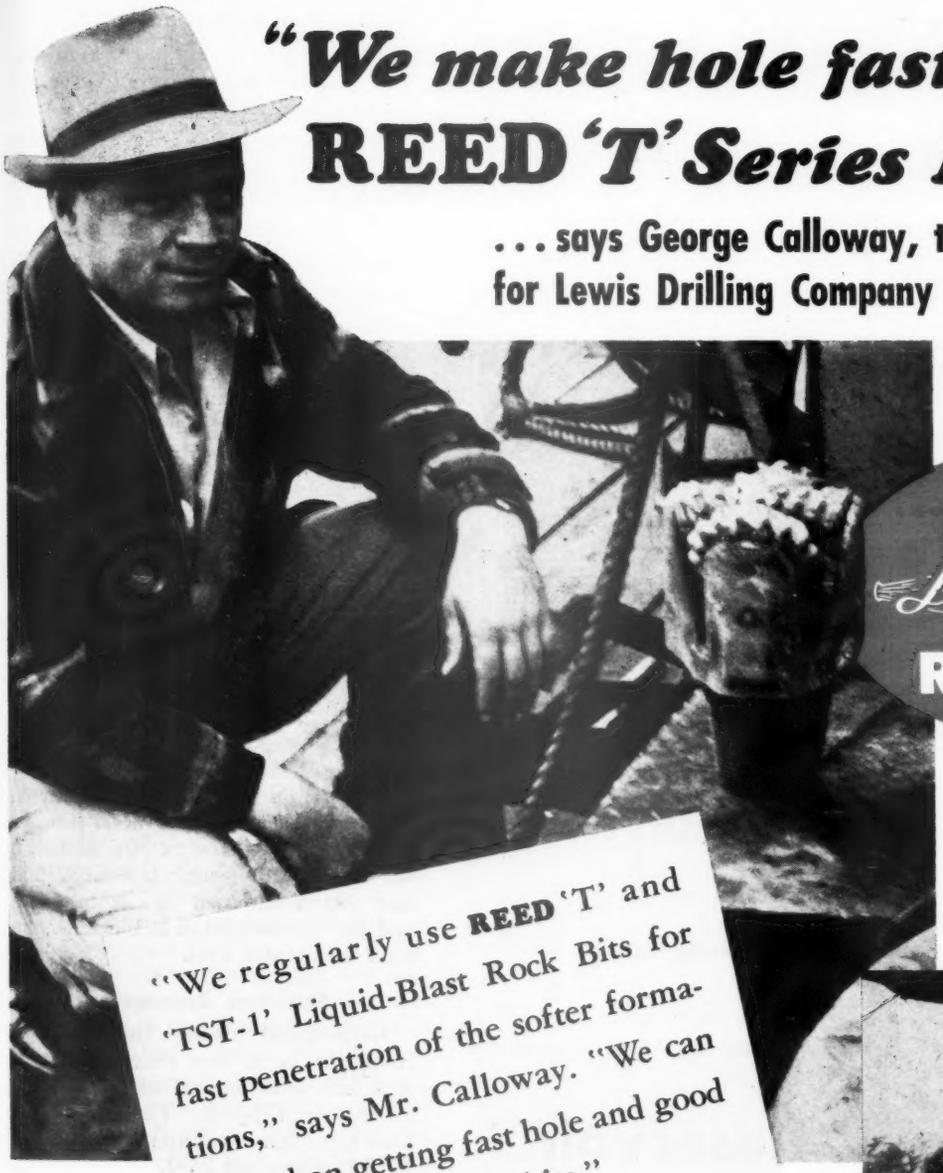

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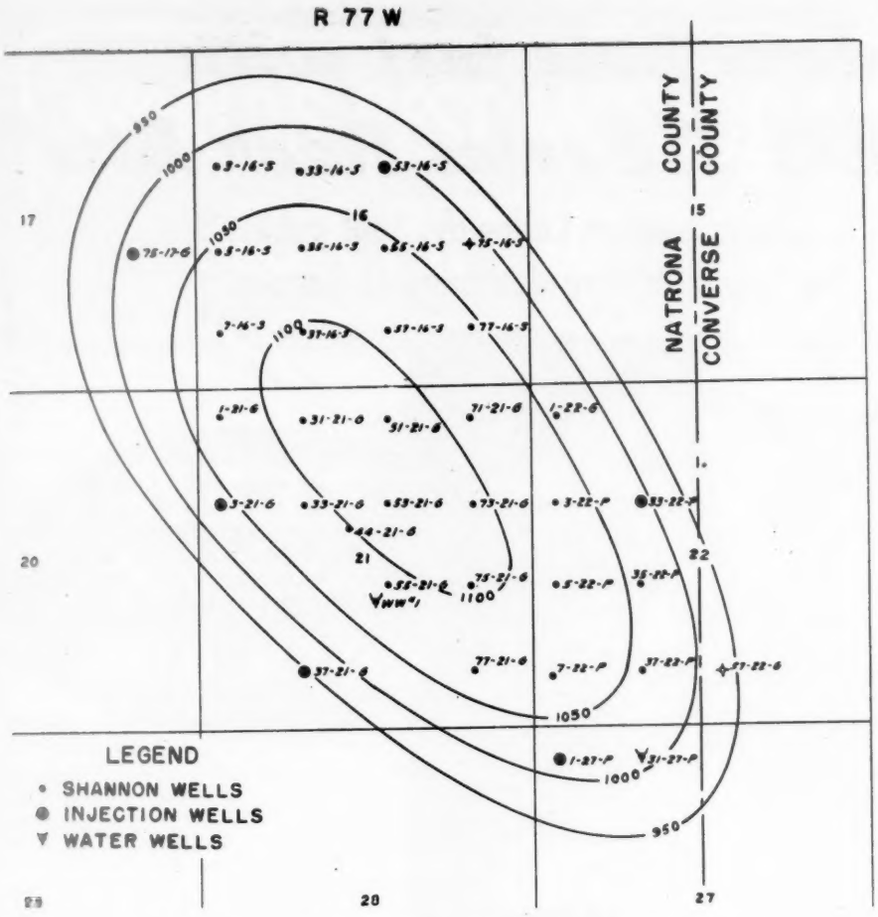


FIG. 1. Structure contour map top of Shannon sand.

Shannon Sand Reservoir Cole Creek Field, Wyoming†

E. J. WHITAKER* and D. T. HOENSHELL*

Abstract

This paper presents the initial results of pressure maintenance in the Shannon Sand Reservoir, Cole Creek field, Wyoming.

The Shannon pool was opened in 1940, and drilling continued through 1945, with 25 wells presently producing. Sixteen hundred twenty acres with a net pay of 17½ ft were found productive, with initial reservoir pressure of 1650 psi. Pressure-production graphs are presented and discussed. Producing pressures at the pump are maintained by a "bubble-point" extension jacket, and have remained at a near-bubble-point minimum. Water injection was begun on February 6, 1946, and increased in 1950, and the history of the water injection is shown graphically. Total injected water was 388,000 bbl to January 1950 and 670,000 bbl to February 1951.

It is believed that the conservation methods in use have effected an increased recovery efficiency and permitted higher producing rates, and will ultimately result in a substantial amount of otherwise non-recoverable oil.

†Presented at the Spring Meeting, Rocky Mountain District, API Division of Production, Casper, Wyoming, April 19-20, 1951.

*General Petroleum Corporation, Casper, Wyoming.

Introduction

The purpose of this paper is to present the initial results of pressure maintenance by water injection and controlled producing pressures in the Shannon sand reservoir, Cole Creek field, Wyoming.

Discussion

Location. The Cole Creek field is situated some 20 miles northeast of Casper, Wyoming, and in the southwestern portion of the Powder River Basin.

Discovery and development. The Cole Creek structure was first indicated by torsion balance and seismic surveys during 1936. The first well, 55-21-G, was spudded September 28, 1937. This well, however, was carried to the Dakota-Lakota zone and placed on production in May 1938. Well 1-21-G was the first to be completed as a Shannon producer, in April 1940, with an initial production of 430 bbl per day pumping. Drilling the Shannon continued through 1945. Two wells originally completed as Dakota - Lakota producers have been recompleted in the Shannon. At the present there are 25 wells producing, one idle, two were abandoned, 6 are in use for water injection, and one was abandoned in the Shannon and later recompleted in the Parkman sand as a water well.

Shannon Reservoir

Geological data. The Shannon reservoir is a low relief, elliptical structure with net oil sand thickness averaging 17½ ft. The producing zone has been encountered as high as 1120 ft above sea level, and the original water table has been established as 980 ft above sea level. Producing area was originally approximately 1620 acres.

The producing sand is Upper Cretaceous, and can be described as fine to medium grained, glauconitic, with thin shale partings and inclusions. Analyses of 231 core samples indicate an average porosity of 19 per cent, interstitial water content 31 per cent, and permeability to air of 56 md.

Engineering data. The Cole Creek field is unitized, and General Petroleum Corporation is the sole operator. Thus, operating practices may be adapted to provide optimum rates, maximum ultimate recovery, and minimum reservoir waste, on the basis of sound engineering principles.

The well spacing plan for development was based on one well per 40 acres, but, after the water table was defined, edge locations were left undrilled. A total of 32 wells were productive from the Shannon, giving an overall average of one well per 50 acres.

Completion practice generally was to set 5½ in. casing above the sand and to drill through with a 4¾ in. bit.

The first Shannon reservoir pressure measured was 1640 psi at the 1075 ft ASL datum, in Well 55-21-G during August 1940. The original reservoir datum pressure has been assumed as 1650 psi.

An analysis of PVT behavior of Shannon oil and gas was made by the General Petroleum production laboratories using recombined surface samples. Characteristics are shown in Figs. 2 and 3. Briefly, the analysis indicated a bubblepoint of 750 psi at the reservoir temperature of 123 F. The total gas-oil ratio was 117 standard cf/barrel with an API gravity of 36.3 deg. Oil viscosity was 3.5 cp at original reservoir conditions and 5.5 cp at atmospheric pressure and reservoir temperature. Reservoir data are shown in Table 1.

Pressure-Production History

Fig. 4 shows a plot of pressure and production data of the Shannon reservoir. It is at once apparent that there is a close relationship between pressure and rates of withdrawal. By the latter part of 1943 it was decided to curtail production in order to arrest the rapid rate of pressure decline. In 1944, pressure surveys indicated that natural water encroachment was sustaining a portion of the production. During 1945 the production rate was increased due to sales commitments, and the pressure again declined. Water injection was begun with one well on February 6, 1946, averaging 250 bbl per day, and "bubblepoint" pumps were installed in 15 wells.

For the next 2½ years net formation withdrawals averaged some 550 bbl per day, and pressure remained constant. In mid-1948 a decision to produce the field at maximum rates was made, and the pressure again declined. During this period the rate of production declined similarly to the pressure, as it had in 1943. It should be noted, however, that the field was able to produce at rates comparable to those of 6 years earlier, even though the pressure was about 250 psi lower. In mid-1949, "bubblepoint" pumps were installed in all producers not previously equipped, and all casingheads shut in. This effected a marked reduction in rate to about 750 bbl per day average during the last quarter of 1949. In January 1950 water injection in Well 53-16-S was begun, and in March, July, and August 4 additional wells were added to the injection system. During 1950 the oil rate consistently increased, to about 960 bbl per day average in January 1951, and the pressure also exhibited a similar increase.

TABLE 1. Reservoir data.

Shannon Sand — Cole Creek field

Number of wells cored	19
Approximate mean depth, ft	4575
Oil-water ratio	.29
Net sand thickness, ft	17½
Porosity, per cent	19
Permeability to air, md	56
Interstitial water, per cent of pore space	31
Productive area, acres	1620
Estimated tank oil originally in place, MM bbl	26.75
Original pressure at 1075 ft ASL, psi	1650
Reservoir temperature, F	123
Characteristics of produced oil:	
Total gas in solution, cf/bbl	117
Oil gravity, API	36.3

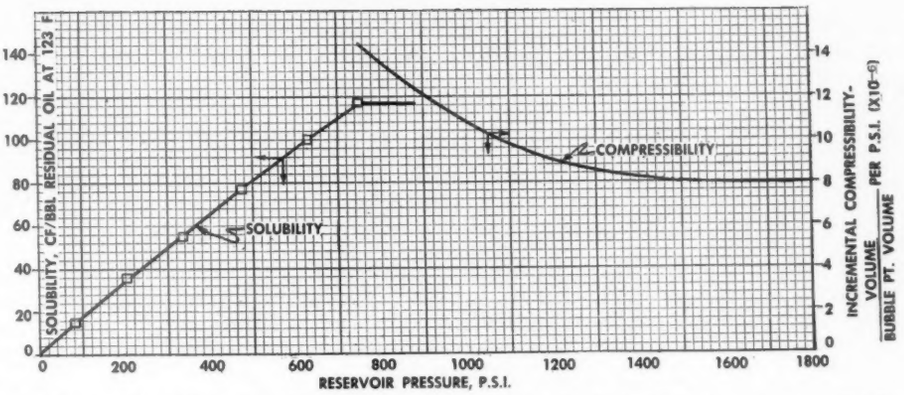

SOLUBILITY, CF/BBL RESIDUAL OIL AT 123 F
SOLUBILITY
COMPRESSIBILITY
INCREMENTAL COMPRESSIBILITY- VOLUME / BUBBLE PT. VOLUME PER P.S.I. (X10⁻⁶)
RESERVOIR PRESSURE, P.S.I.

FIG. 2. Solubility by differential liberation at 123 F, left; right, compressibility of bubble point mixture at 123 F.

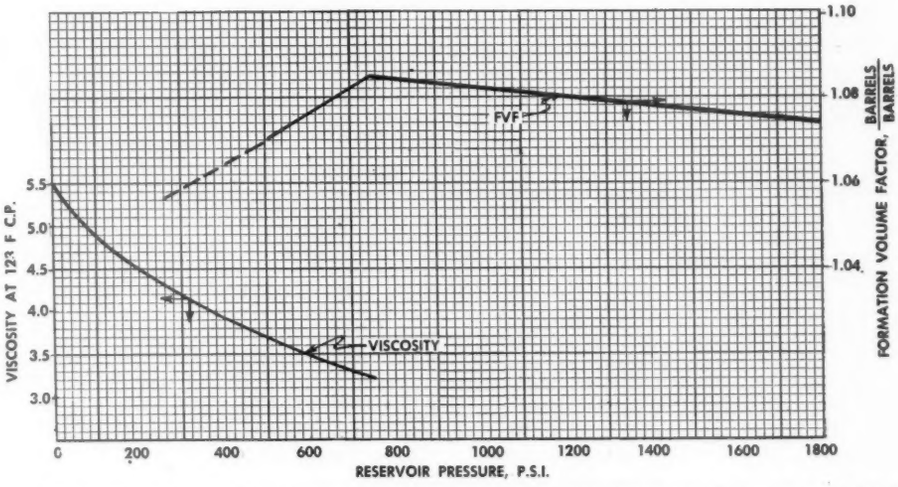
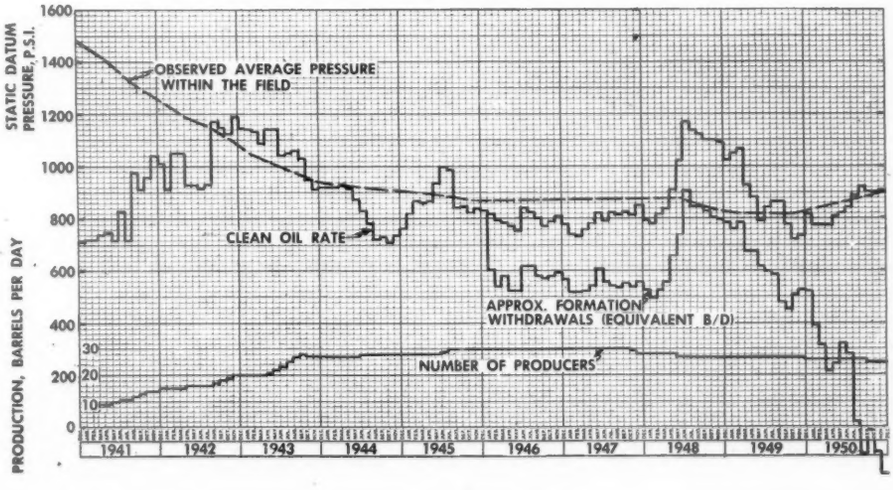


FIG. 3. Top, formation volume factors. (Barrels of bubble point liquid at 123 F per barrel of tank oil. Bottom, oil viscosity.

The "Bubblepoint" Pump

Mention has been made of the installation of "bubblepoint" pumps in the Shannon wells. This pump is

FIG. 4. Pressure production history—Shannon reservoir.



simply a standard RLT pump, with the addition of a 15 ft extension between the bottom of the pump barrel and the standing valve. The pump is very sensitive to free gas, and will gas-lock when producing pressure drops below the bubblepoint and gas evolves from solution. This tends to maintain a backpressure on the formation near the bubblepoint pressure, when, of course, the casinghead is shut in and casing pressure is stabilized. Observations indicate that producing pressures have remained within 150 psi of the bubblepoint pressure. As compared with other methods of maintaining a back-pressure on a producing sand, the "bubblepoint" pump, operated with casinghead shut in, has proved very satisfactory.

Water Injection

As it becomes evident in 1943 that natural water encroachment would not support pressure and oil rate at the desired levels, engineering thought was given to a water injection project. Water flow tests were made on cores, and injection experiments were made on several wells in the field. Well 37-21-G was finally selected and initial injection was started on February 6, 1946. This is a closed system involving a water well, purification and treating plant, and injection well, all housed together with a tail pump on the water well unit providing injection power. Water was injected at a rate of 200- 300 bbl per day against pressures up to 350 psi. This unit is still in operation, and has injected some 462,000 bbl of water in the 5 years to February 1951. It is believed to be the first water injection project in the Rocky Mountain area.

In January 1950, Well 53-16-S was placed on injection, as the first of several wells on a closed system. In March, Well 75-17-G was added, and in July and August 3 more wells were added to the system. Water is produced from a water well producing about 800 bbl per day from the Parkman sand and another producing about 300 bbl per day from a shallower sand. Produced water at each well is surged in a gas-capped pressure vessel and injected via a common system by slush pumps. Regulation of rate per well is controlled at the well heads. All of the five wells have not filled with water to date, and individual well-head pressures vary from zero to 90 psi.

History of the 6 injection wells, 5 of which were formerly producers, is shown in Fig. 5. Injectivity indices of these wells range up to 1.0 bbl per psi pressure increase, and are individually up to 30 times the highest recorded productivity index.

Total injection rate has averaged 1100 bbl per day since August 1950, and a total of 670,000 bbl of water have been put into the reservoir.

Inferred Results

Examination of the pressure-production behavior of the Shannon reservoir shows something of the effect of water injection and controlled withdrawal.

Initial control of withdrawals in 1944 arrested the rapid pressure decline, but the 900 bbl per day average rate was appreciably higher than the natural water encroachment rate. After the start of water injection in 1946 the total amount of water entering the reservoir was sufficient to sustain an oil rate of 800 bbl per day without pressure decline. It is estimated that during this period the natural water drive was about 700 equivalent barrels per day, and the injected water about 50 per cent effective.

After the attempt to produce the sand at 1200 bbl per day rate in 1948, and the later control of producing rates by installation of "bubblepoint" pumps, field average pressure was about 810 psi and net oil rate averaged 750 bbl per day during the last quarter of 1949. Estimated natural water encroachment was about the same as before, and augmented by some 250 bbl per day of injected water, still about 50 per cent effective. (The increased rates of 1948 were almost entirely supported by solution gas drive). The lower static pressure at the end of 1949, with "bubblepoint" control, was effecting an automatic withdrawal rate control beneficial to reservoir pressures.

With the augmented injection in 1950, the increase in static pressure has resulted in an oil rate about 200 bbl per day higher than at the beginning of the year. At present both the static pressure and the production are increasing.

Calculations indicate that to the present, some 400,000 bbl of oil have been recovered by these conservation methods, which would not have been recovered by pressure depletion alone. The apparent recovery efficiency in the area swept by water to the middle of 1950 was in the order of 36 per cent. With the present distribution of injection wells, it is believed that the augmented water sweep will be more effective than the natural water drive, due to pressure maintenance within the pool which will prevent separation of solution gas in the sand pore space, and will also tend to prevent the rapid bypassing of tight lenses or strata. Thus, it is estimated that the ultimate recovery efficiency will be greater than 36 per cent, and a 4 per cent increase would mean some 1,000,000 bbl, otherwise non-recoverable.

Conclusion

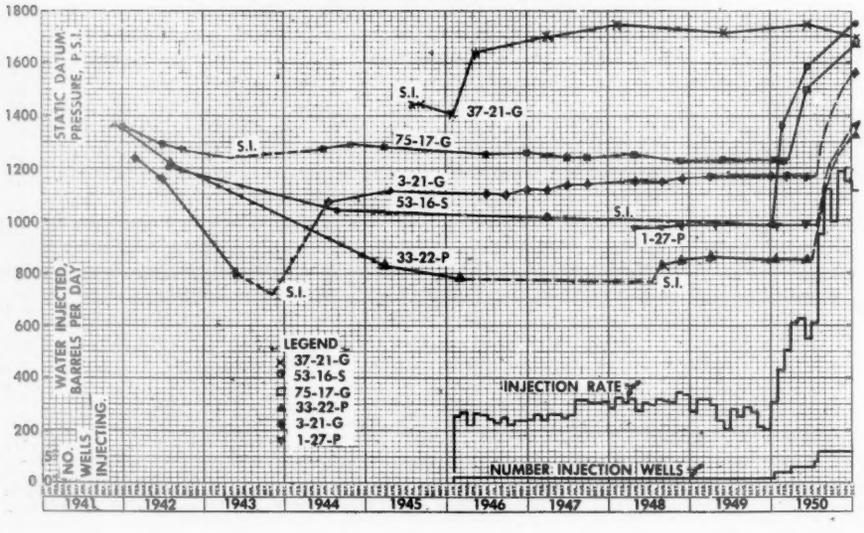
It is still too early in the life of the injection project to appreciate quantitatively the full results of the endeavor. It is believed, however, that the conservation of reservoir pressure and energy has effected an increased recovery efficiency and permitted higher producing rates, and will ultimately result in a substantial amount of otherwise non-recoverable oil.

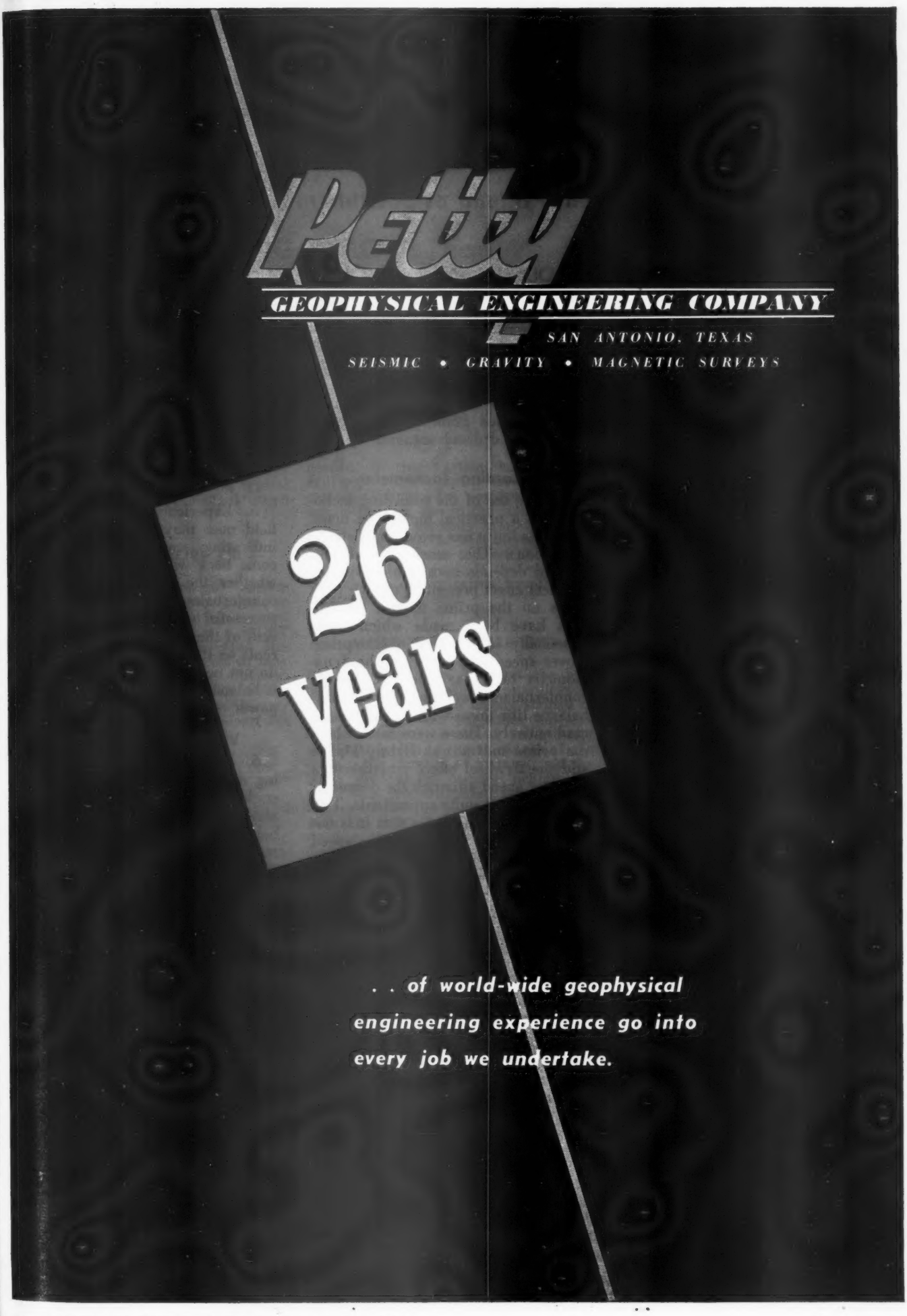
The project is another step in the practical application of sound engineering principles in the control of reservoir performance for the purpose of increasing ultimate recovery, prevention of the waste of reservoir energy, and conservation of natural resources.

Acknowledgments

The writers wish to express their appreciation to the management of General Petroleum Corporation for permission to publish this paper. ★

FIG. 5. Water injection history, Shannon reservoir.

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Counterbalancing of Beam Pumping Units†

Adjustment must be done with more care than ever in these times—Pumping units should carry as heavy a load as possible to conserve scarce metal

DOUGLAS O. JOHNSON*

OVER the period of the last 16 years many articles have been written and formulas have been proposed that had as their purpose a better understanding for the oil producers of the importance of proper counterbalancing of beam pumping installations.

In the past, pumping units were built with extra steel and extra capacity in them so as to offset to a great extent the abuses imposed on them by improper attention to the adjustment of counterbalance and adjustment of all of the other factors which would tend to minimize peak loads and torques.

At the present time pumping units are being designed with definite ratings to take care of definite peak loads and peak torques, and because of the competitive market the extra "padded" capacity is fast fading out of the picture. This of course means that it becomes a necessity to measure the loads and torques to which the pumping units are being subjected. In many instances it does not require very much unbalance to go beyond the rating of the unit.

The present defense effort, with the necessary conservation of steel, makes it more imperative that pumping units and all equipment be loaded as heavily as practical so as not to use up unnecessary steel.

Simple procedures have been presented by various authors over the past 16 years for the adjustment of counterbalance, and these may be enumerated as follows:

1. Recording tachometer.
2. Measurement of belt tension.
3. Slipping of the clutch.
4. Listening to the sound of the prime mover.
5. Indicating ammeter showing peak current used by electric motor drive.
6. Vacuum gage readings taken on engines.
7. Measurement of the actual counterbalance effect at the polished rod with a dynamometer.

It would be well at this point to have a brief discussion of each of these methods pointing out the advantages and disadvantages.

Recording Tachometer

1. The use of the recording tachometer is a practical method in many instances but it has some very definite limitations. The sensitivity of this method depends upon the amount of flywheel effect present to absorb peak loads on the prime mover. Recordings have been made which show practically no variation in prime mover speed and yet when the dynamometer card was recorded and the counterbalance weighed, the counterbalance line missed the dynamometer card entirely. These were cases where the prime mover was lightly loaded and the flywheel effect maintained a constant speed although the degree of unbalance was quite appreciable. This method is also tricky in that it is not always possible to even up the speed variation on the upstroke and downstroke. This results from the complex consideration of the geometry of the pumping unit and the shape of the load characteristic recorded by the dynamometer. Fig. 1, 2, and 3 illustrate the above points.

Measuring Belt Tension

2. Measurement of belt tension was used chiefly on the large flat belts that were extensively used in the past; but since practically all units now are operated with multiple V-belt drives, there is no practical use being made of this today.

Slipping Clutch

3. Slipping of the clutch is a fairly good method but is not always practical, especially where large rotary weights are being used. Also, this means that the clutch must be in good condition, which may or may not be the case.

Prime Mover Sound

4. Using the sound of the prime mover is best suited for electric motor drives and may or may not be a good method for multi-cylinder engines, depending on the action of the engine governor and the shape of the dynamometer card.

Operator's Skill

5. Experience shows that several field men may be sent out with an indicating ammeter and they will come back with different ideas as to whether the well is over or under counterbalanced. In other words, the successful operation depends on the skill of the operator. Equal peak currents on the upstroke and downstroke do not necessarily mean that the well is balanced so as to require minimum power requirements.

Vacuum Gage Readings

6. Experience shows that in relying on vacuum gage readings on the engine to determine best counterbalance, the result leads to an overbalanced condition. In order to obtain results from this method, an experienced operator would be required, and each type of engine and well condition would need special interpretation.

Measuring at Polished Rod

7. Experience over the last 3 years proves that counterbalancing is best understood by the field men when the counterbalance effect is weighed at the polished rod as a regular procedure in taking dynamometer readings. This method allows an immediate comparison between the counterbalance effect and the maximum and minimum well loads and gives an immediate picture of normal and abnormal load characteristics. It records a quantitative measurement from which the amount of unbalance can quickly be determined. Counterbalance tables may then be consulted and the amount of change necessary can be made at a minimum of time and expense. If the field crew is available

†Presented at the Spring Meeting, Mid-Continent District, API Division of Production, Herring Hotel, Amarillo, Texas, March 21-23, 1951.

*Johnson-Fagg Engineering Company, Tulsa, Oklahoma.

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—MORE THAN MORE OIL—

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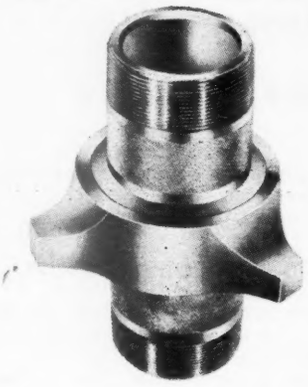

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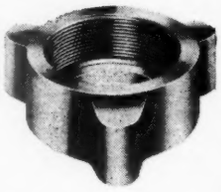

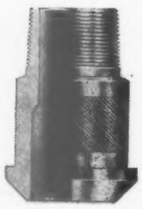

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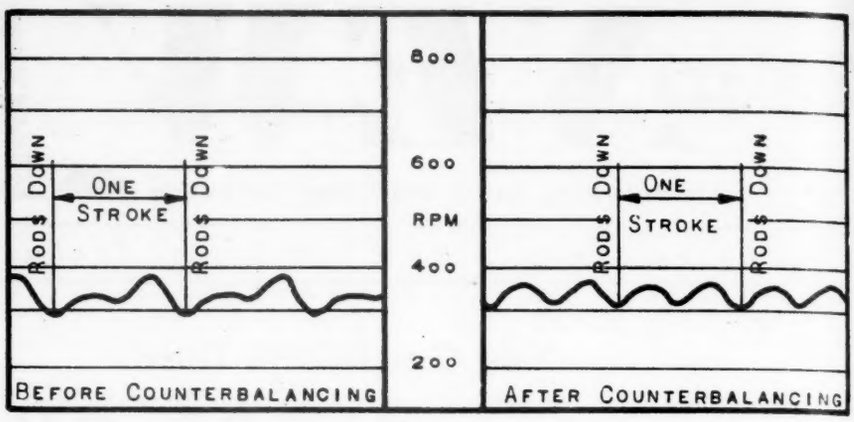

FIG. 1.

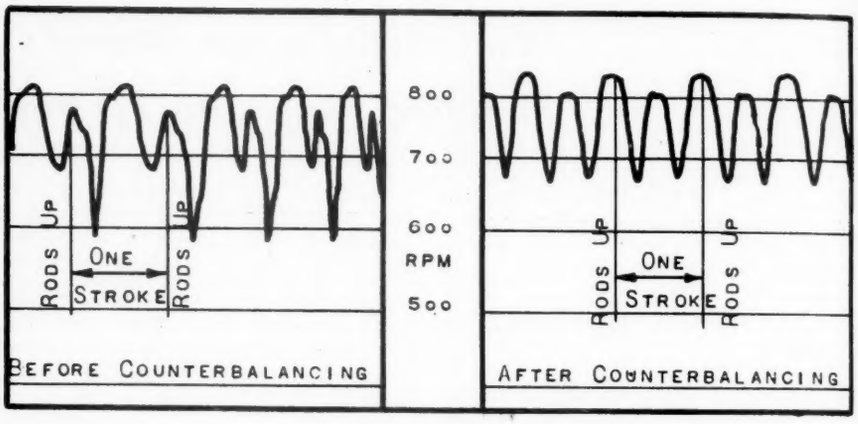

FIG. 2.

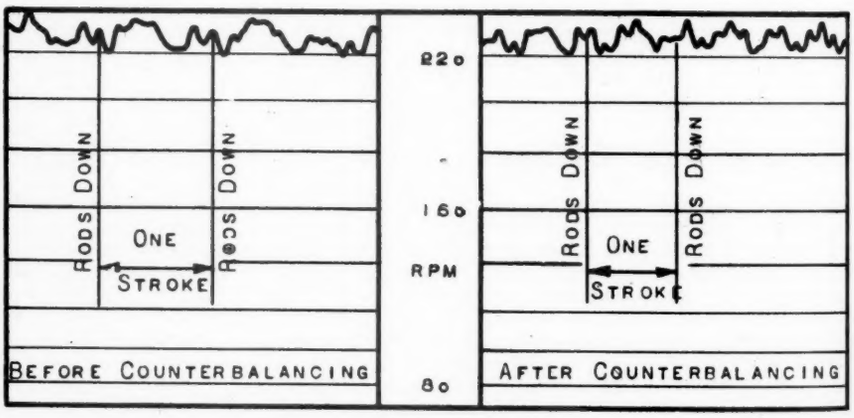

FIG. 3.

to do the work immediately, a check can then be made to see whether the desired amount was obtained. On some units the adjustment can be easily made in a few minutes.

When pumping conditions are unstable it is very difficult to select the best counterbalancing for the conditions unless dynamometer cards are taken.

After a pumping installation has been properly counterbalanced—or a better statement would be "counterbalanced as well as it can be under the operating conditions existing"—then there still remains the problem of determining whether the peak-torque rating of the pumping unit is being exceeded. We can assume that the pumping motion is simple harmonic and under these conditions compute the approximate peak torque. However, this does not take into account the actual rig geometry and the variation in prime mover speed. Kemler has shown in his paper "Counterbalancing of Oil-Well Pumping Machines."[1] How the velocity of the polished rod may be obtained by making a detailed layout of the pumping unit and solving for the instantaneous velocity by means of vectors.

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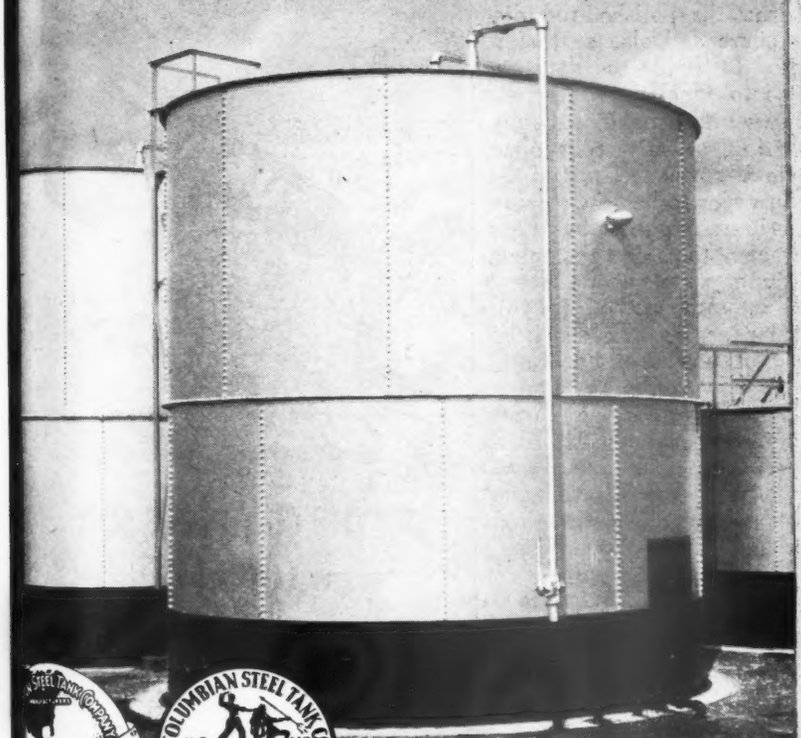

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Mills has shown how counterweight and well-load torque may be calculated from the rig geometry and dynamometer load data. This method also involves the detailed layout of the pumping unit.

If a timing wave is recorded simultaneously with the dynamometer card, the velocity of the polished rod may be computed without any additional measurements. By making a record of the instantaneous prime mover speed with a recording tachometer, the analysis may be carried far enough to obtain an instantaneous torque curve.

This type of analysis automatically takes into account the geometry of the pumping unit and the variation in speed of the prime mover.

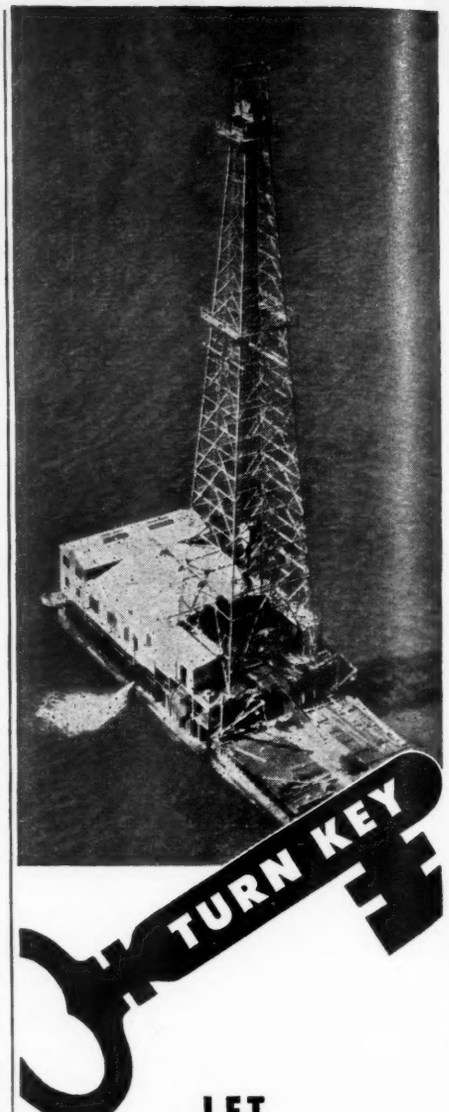
The following is the step-by-step procedure in making a kinematic analysis of a pumping unit. (See Figs. 4, 5, and 6.)

The timing wave is made simultaneously with the dynamometer card, but must be placed in the proper position to draw the polished-rod displacement curve and also so that it may be used to divide the dynamometer card into equal time intervals.

The timing cycle should be numbered, starting at any convenient point, preferably near the start of the upstroke. In order to help in keeping this numbering straight, it has been found convenient to project the points where the timing wave cuts the central axis, taking into account both the full cycles and half cycles. The next step is to choose a convenient horizontal scale, which may be either timing cycles or time in seconds, and carrying the projections across and plotting the displacement vs. time curve. This procedure is shown by the top set of curves on each of Fig. 4, 5, and 6. As a convenient comparison, a simple harmonic curve has also been plotted.

In order to plot the polished-rod velocity curve, the small increments of distance are measured carefully from the original of the timing wave. The ratio of the length of the pumping stroke measured at the polished rod to the overall length of the timing wave gives the overall reduction ratio of the recording, and from this may be determined the actual distance the polished rod travels for each increment of time. By knowing the distance and the time elapsed, the average velocity for each increment may be calculated and plotted, and when sufficient points are determined the polished-rod velocity curve is plotted.

As a check on this procedure the average upstroke and downstroke velocity may be determined by the use of a planimeter measuring the area contained between the velocity curve



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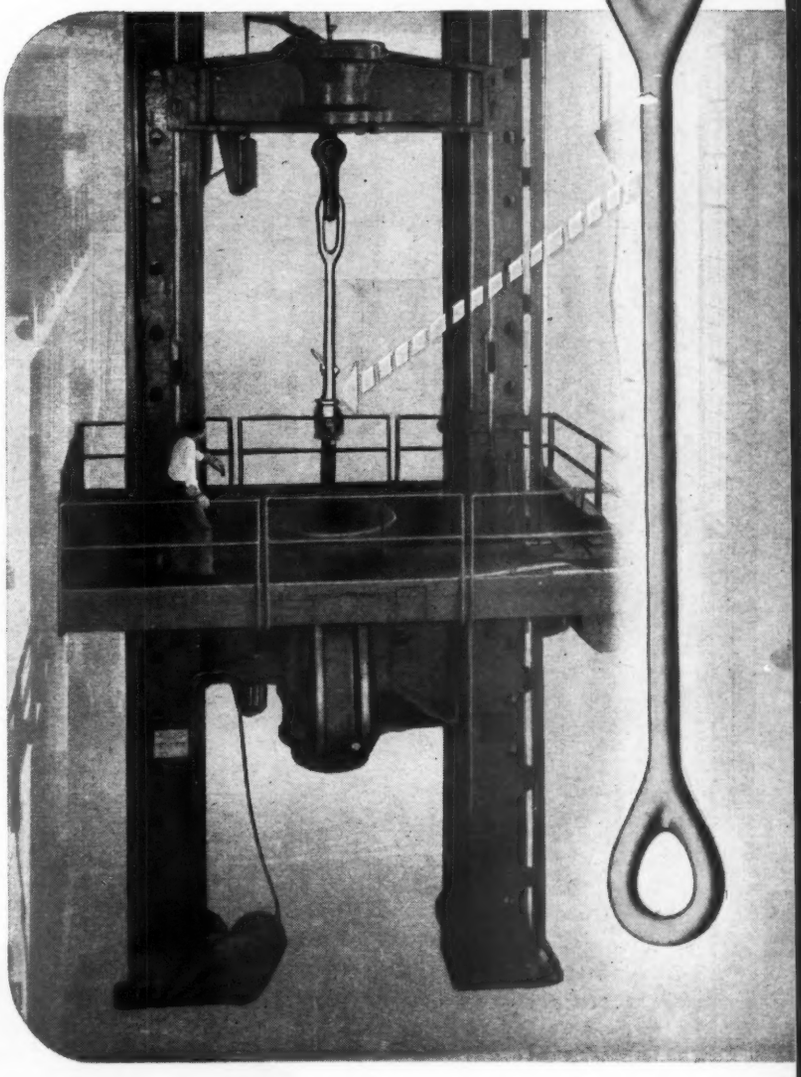

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Shank Diameter INCHES	*Rated Capacity* TONS PER LINK	
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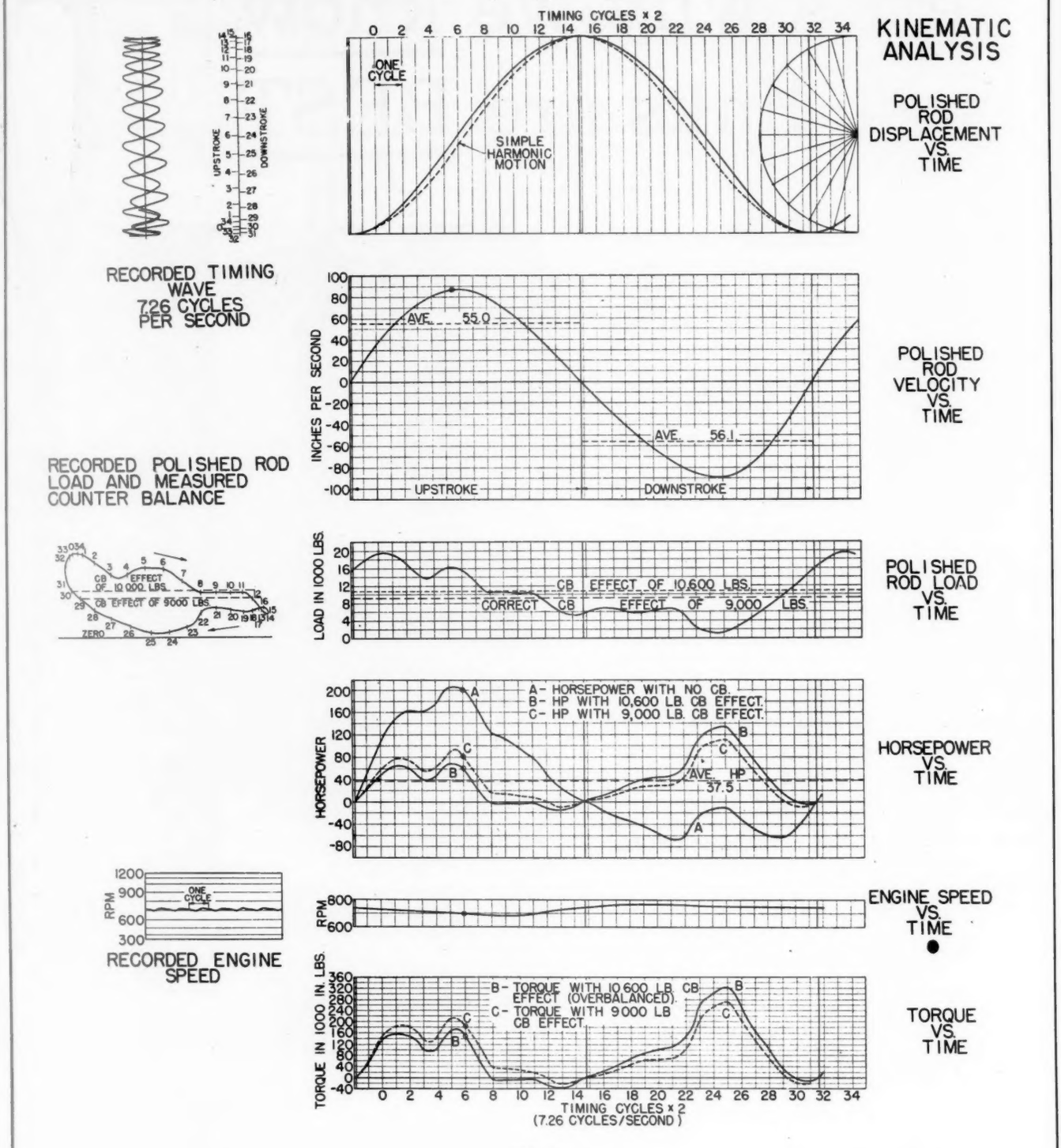

FIG. 4

and the zero line and then dividing by the length of the zero line to give the average height. This average velocity should check with the average polished-rod velocity determined by counting the strokes per minute with a stop watch.

In order to divide the dynamometer card into equal time intervals, the following procedure should be followed. (See Fig. 7.)

The center line of the main stylus must be located with reference to the base reference line, and the axis of the timing wave placed on this center line in a position where an arc drawn with a radius equal to the length of the recording stylus will just touch the dynamometer card at each end. With this same radius of arc each one of the numbered timing cycles may be scribed off on the upstroke and downstroke.

The polished-rod load vs time curve is then plotted by projecting the load characteristic on the same time base to which the displacement and velocity curves were plotted.

When the prime mover speed is recorded with a recording tachometer, care should be taken to mark the position of the speed at one end of the pumping stroke. As the popular type of tachometer also records one-second "pips," the variation in speed over one pumping cycle may be plotted in

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the correct relationship with the rest of the curves on the same time axis.

When the instantaneous velocity at a particular point is known, and the instantaneous load, the product of the two is proportional to the instantaneous horsepower. When a sufficient number of points are considered, the instantaneous horsepower curve may be drawn showing what it would be without any counterbalance and also what it is with the counterbalance as measured at the polished rod.

In order to check the horsepower curve, the area of the entire curve above the zero line may be measured with a planimeter and the average horsepower computed, and this should check with the regular polished-rod horsepower.

In order to obtain the instantaneous torque curve, the instantaneous speed of the crank is computed from the prime mover speed and the torque curve is then proportional to horsepower divided by the instantaneous speed.

The following is a sample calculation with detailed values from the analysis in Fig. 4.

Sample Calculation

1. *Velocity Curve.*

Overall length of timing wave = 3.68 in.

Measured length of polished-rod stroke = 64 in.

Overall reduction ratio = 64/3.68 = 17.4.

Consider the increment of travel between points 9 and 10. Each half cycle has been numbered.

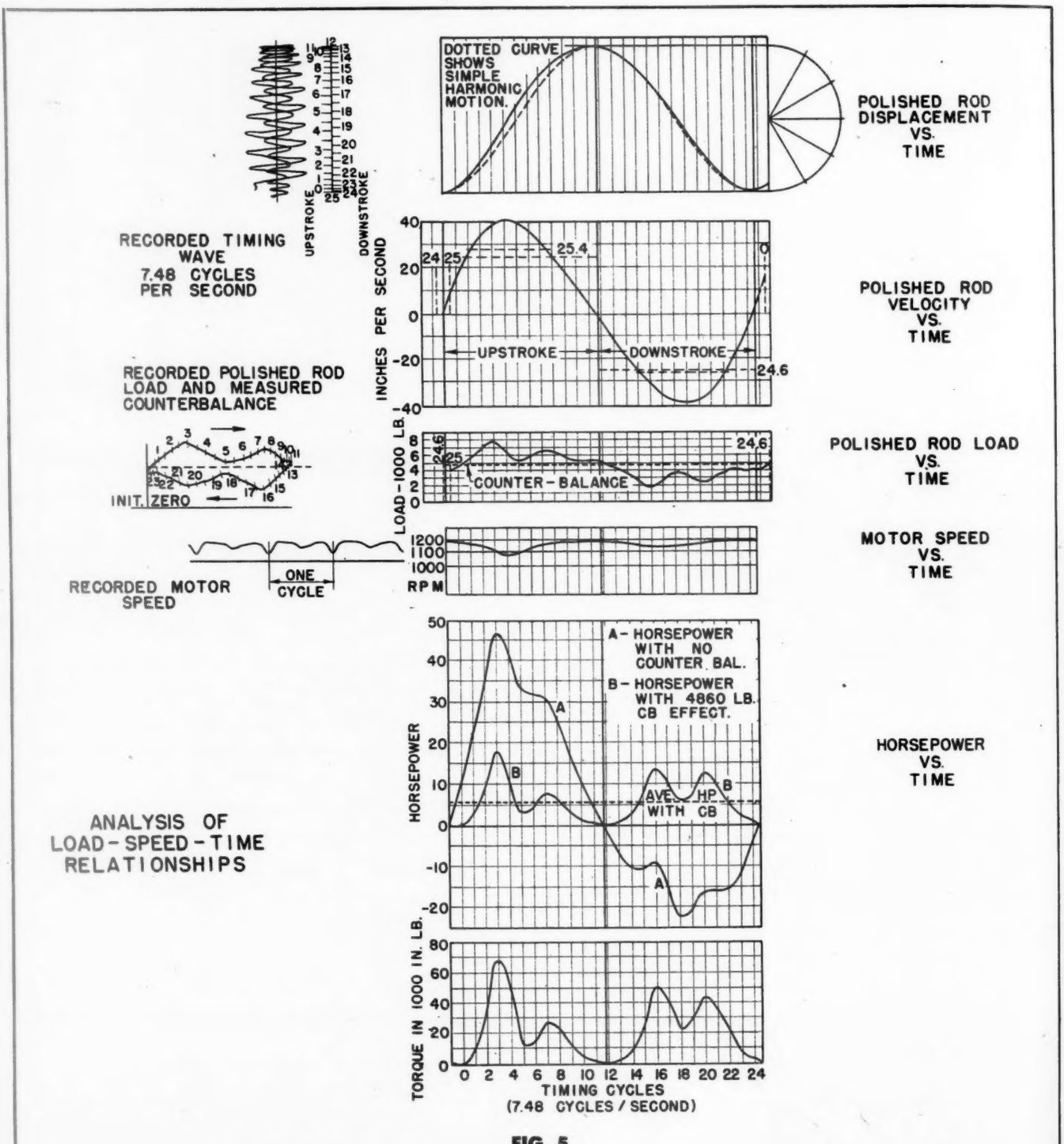

FIG. 5

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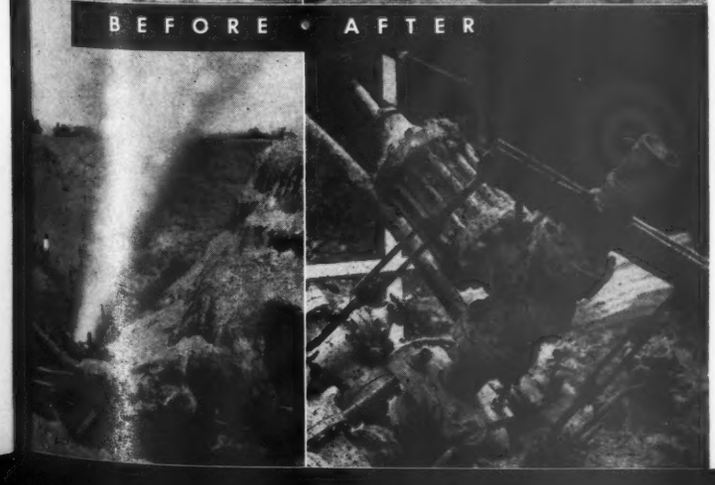

Again Cameron equipment has flown to the rescue of operators in distress on opposite sides of the world. To Venezuela and Iran, on recent consecutive week-ends, were flown special capping manifolds fabricated from Cameron Pressure Operated Valves and Wellhead Equipment as prescribed by the famous wild well fighters of M. M. Kinley Co.

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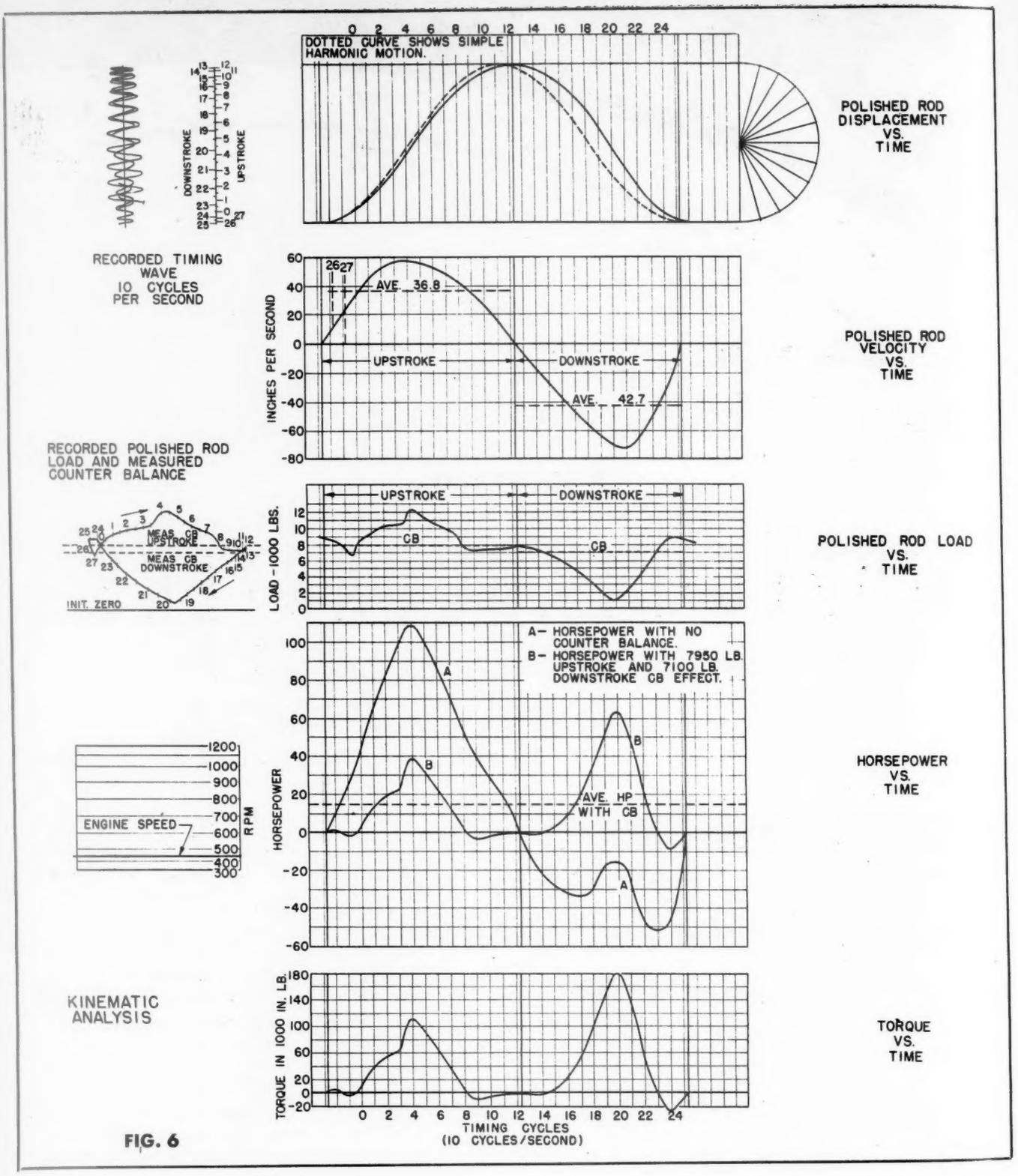
DOTTED CURVE SHOWS SIMPLE HARMONIC MOTION.
POLISHED ROD DISPLACEMENT VS. TIME
RECORDED TIMING WAVE 10 CYCLES PER SECOND
DOWNSTROKE
UPSTROKE
INCHES PER SECOND
AVE. 36.8
AVE. 42.7
POLISHED ROD VELOCITY VS. TIME
RECORDED POLISHED ROD LOAD AND MEASURED COUNTER BALANCE
MEAS. CB UPSTROKE
MEAS. CB DOWNSTROKE
INIT. ZERO
LOAD - 1000 LBS.
CB
POLISHED ROD LOAD VS. TIME
A- HORSEPOWER WITH NO COUNTER BALANCE.
B- HORSEPOWER WITH 7950 LB. UPSTROKE AND 7100 LB. DOWNSTROKE CB EFFECT.
ENGINE SPEED
RPM
HORSEPOWER
AVE. HP WITH CB
HORSEPOWER VS. TIME
KINEMATIC ANALYSIS
TORQUE IN 1000 IN. LB.
TORQUE VS. TIME
TIMING CYCLES (10 CYCLES/SECOND)

FIG. 6

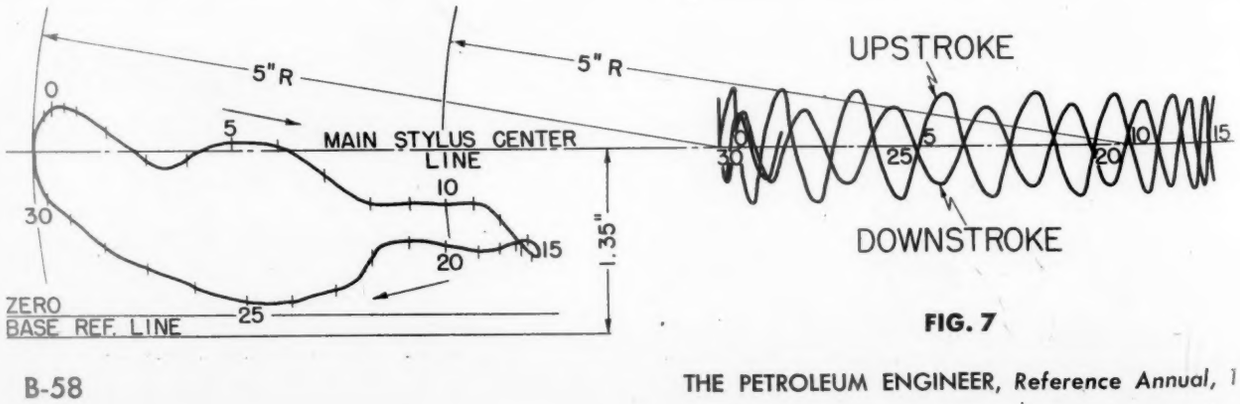
5"R
5"R
MAIN STYLUS CENTER LINE
ZERO BASE REF. LINE
1.35"
UPSTROKE
DOWNSTROKE

FIG. 7

Distance from point 5 to 6 = 0.336 in.

Since the timer frequency in this case = 7.26 cycles per sec. the average velocity from point 5 to 6 (½ cycle) would be:

$$\frac{0.336 \times 17.4}{\left(\frac{1}{2 \times 7.26}\right)} = 85 \text{ in. per sec.}$$

This value is then plotted midway between ½ cycle 5 and 6 as shown at point.

2. *Instantaneous Horsepower Cycle.*

Now consider the number 6 point for calculation of instantaneous horsepower.

From velocity curve, velocity = 86.0

From load curve, load = 15,400

A. Instantaneous horsepower no counterbalance:

$$hp = \frac{\text{Load} \times \text{Velocity}}{12 \times 550} = \frac{15{,}400 \times 86}{12 \times 550} = 202$$

B. Instantaneous horsepower 10,600 lb counterbalance effect:

Unbalanced load = 15,400 — 10,600

$$hp = \frac{(15{,}400 - 10{,}600)\,86}{12 \times 550} = 62.5$$

C. Instantaneous horsepower counterbalance effect corrected to 9000 lb:

$$hp = \frac{(15{,}400 - 9000)\,86}{12 \times 550} = 83.0$$

3. *Instantaneous Torque Curve*

Consider number 6 point for calculation of instantaneous torque.

From the fundamental relationship:

$$hp = \frac{2\pi(\text{rpm})\ (\text{torque})}{33{,}000\ (12)}$$

The expression for torque becomes:

$$T = \frac{63{,}000 \times HP}{\text{rpm}}$$

Then for the above B condition:

$$T = \frac{63{,}000 \times 62.5}{26} = 150{,}000 \text{ in.-lb}$$

For the C condition:

$$T = \frac{63{,}000 \times 83}{26} = 190{,}000 \text{ in.-lb.}$$

All of the sample calculation points are circled on Fig. 4.

The present formula for calculating peak torque, as given in API Std 11-E, has been discussed on many occasions and found to give misleading results, but it has served the purpose of making everyone cognizant of the fact that gear boxes should be rated on a peak-torque basis rather than a horsepower basis as they were originally. In making computations for peak torque, the following procedure has been found to give results closer to the measured results because the counterbalance effect is not taken as a certain definite percentage of the peak load, but rather a mean between the peak load and minimum.

The peak load is calculated as follows:

$$PL = W_f + W_r\ (1 + C)$$

Wherein:

PL = polished-rod load, lb

W_f = weight of fluid, lb (area of plunger-area of rods) × (psi)

W_r = weight of rods, lb

L = length of stroke, in.

N = number of strokes per minute.

$$C = \text{acceleration factor} = \frac{N^2 L}{70{,}500}$$

The minimum load is calculated as follows:

$$PL\ (\text{min}) = W_r(1\text{-}c) - W_r \times \frac{62.5}{490}$$

Values of W_r and c are the same as used for peak load.

The amount of counterbalance effect is then taken as the mean and the unbalanced load as the difference between this effect and the maximum and minimum loads.

This unbalanced load multiplied by half the length of the stroke gives the peak torque.

This procedure also ties in closely with the theoretically correct counterbalance, which is the weight of the rods plus one-half of the fluid weight.

The simplicity of the present API formula is commendable but it is felt that this could be supplanted by another simple relationship such as the one given above, which would get closer to the answer.

In using all of the various counterbalance tables which are presented by the various pumping-unit manufacturers, it is found that there is considerable misunderstanding and as a consequence these tables lose a great deal of their effectiveness. In many cases it is very difficult to identify the type of crank and weight in the field to tie it in with the tables given.

It is proposed that steps be taken to simplify the presentation of the counterbalance effect so that it may all be tied in with the measurements that can be made readily in the field. This should result in an advantage to everyone concerned.

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1. Emory N. Kemler, "Counterbalancing of Oil-Well Pumping Machines," *Drilling and Production Practice*, 87, (1943) with discussion by D. O. Barrett.
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6. H. S. Kelly, M. H. Halderson, P. A. Witherspoon, and E. S. Calvert, "Factors Affecting the Accuracy of Peak-Torque Calculations Using Dynamometer Cards," *Drilling and Production Practice*, 160 (1948). ★ ★ ★

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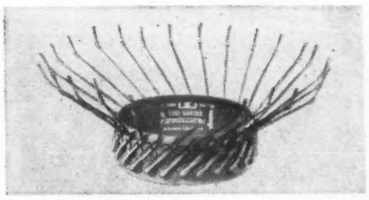

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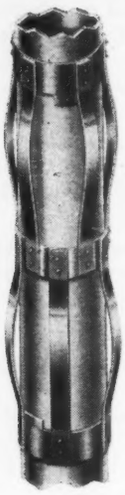

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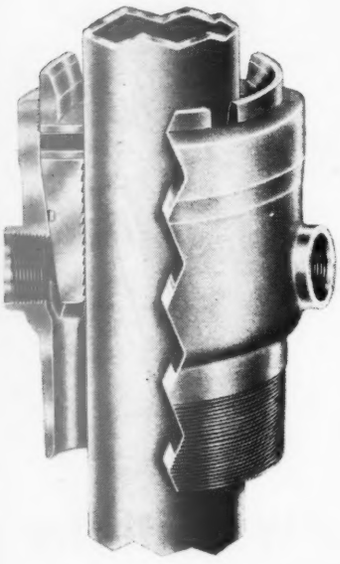

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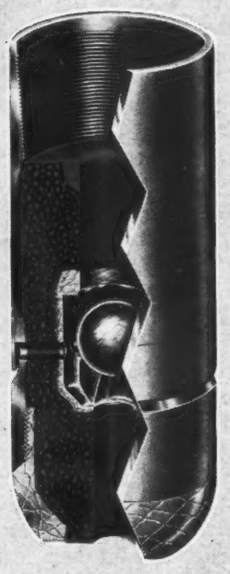

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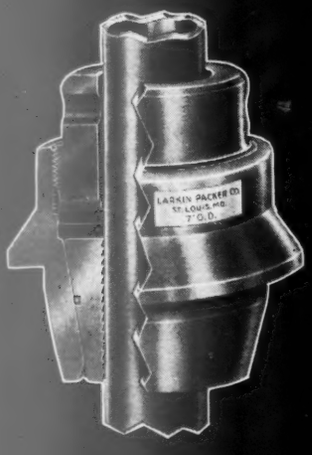

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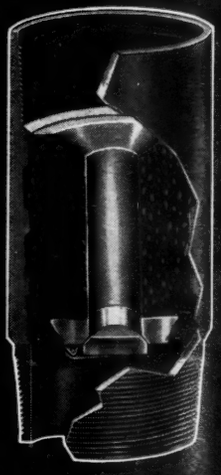

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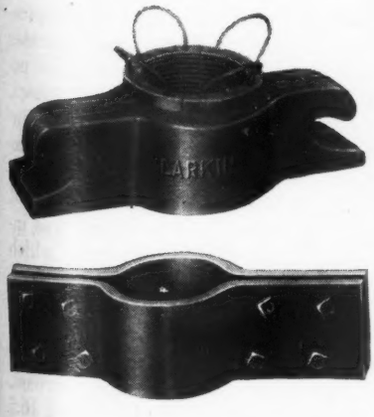

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Results From Increased Flooding Pressures†

E. T. Heck* and J. C. Vaughn*

THIS paper is primarily concerned with the practical aspects of changes in flooding pressures over relatively short periods on actual leases. As background information, however, the following comments are pertinent to the present discussion.

The precise mechanism of fluid flowing through an oil sand is imperfectly known. The currently accepted theory for reservoir engineering denies the possibility of materially effecting the ultimate recovery of oil by changing pressure gradients. On the basis of this theory, Dickey and Buckwalter[1] in 1946 discussed the advantages of increased injection rates at water input wells.

In that paper, they gave both mathematical computations and a few examples, to illustrate a definite economic benefit to be derived from increased injection rates. It was pointed out in that paper that an increase in pressure late in the life of the flood would almost automatically result in an increase in ultimate recovery due to the fact that operating costs are relatively constant for moderate changes in fluid through-put.

Attempts have been made to investigate the effects of variations in pressure gradient on the flooding processes in the laboratory. The resulting data have been somewhat conflicting and there are still proponents on both sides of the question of high pressure vs low pressure.

J. W. Breston and Richard V. Hughes[2] reviewed some of the more pertinent laboratory data and presented their own data showing a definite benefit in ultimate oil recovery by the use of higher pressures in long core experiment. As pointed out in that paper, all laboratory experiments are subject to challenge on the basis that they do not entirely duplicate field conditions. It is an interesting fact, however, that the closer and closer laboratory experiments approach conditions believed to exist in the field, the more and more they indicate that increased pressures yield more oil. Some of the material presented in this paper seems to support Breston and Hughes.

As expressed above, the primary purpose of this paper is to study the practical aspects of increasing pressures on existing floods. Oil field personnel have repeatedly objected to increasing pressures for a variety of reasons. For example: 1. The increased pressure will result in numerous water leaks in the pressure lines. 2. The increased pressures will result in a marked increase in pulling costs on the oil wells. 3. The increased pressures will result in putting a lot of water through the sand without a similar increase in oil (i.e., increased water-oil ratios). 4. The cost of energy to inject the water and pump the oil wells will increase out of all proportion to any benefits derived. The data presented herein are intended to answer these specific questions. No effort is made to plot the material to show the long range effect of increased pressures on ultimate oil production.

Discussion of Data

Fig. 1 shows the pertinent information with respect to the Brooks lease, situated in the Bradford field in Pennsylvania. Shown on the graph are the plant pressures involved, the number of water line leaks reported, the number of oil wells pulled and the rate of oil production.

This lease has been under flood for approximately 8 years. As so frequently happens, both the number of water line leaks and frequency at which oil wells are pulled fluctuate greatly. There is, however, a very definite increase in the number of water line leaks coincident with the pressure increase. This is particularly true in August and September, 1950, when the pressure was raised to about 100 psi plant pressure. The number of leaks did, however, return to what appears to be the normal level during October, November, and December, 1950, so that this particular effect was only temporary. There was no observed increase in the number of oil wells pulled following the pressure increase. The oil production curve on Fig. 1 is not plotted in a manner that would permit a direct quantitative interpretation of the effect of increased pressure on the oil production rate. The fact that there was an increase in oil production is, however, readily apparent. The following figures are pertinent to the economics of this pressure change on the Brooks lease. The plant pressure was raised from 950 lb to 1100 lb, which means a sand face pressure increase from 1500 lb to 1650 lb. This is a 16 per cent increase in energy in the form of water pressure at the pressure plant and a 10 per cent increase in effective water pressure delivered to the sand face at the injection wells. The rate of water injection increased 12.5 per cent as a result of the pressure increase. The rate of water production increased only 6.5 per cent. The rate of oil production increased 16.5 per cent. The combined gas and electric cost for the lease increased 14 per cent following the pressure increase and as this cost of energy represents only 20 per cent of the total lifting cost, the over-all increase in lifting cost was only 2.8 per cent.

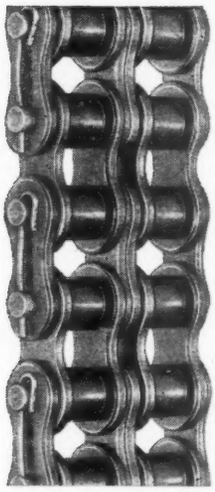
Fig. 2 shows similar information for the Burns lease in the Bradford field in Pennsylvania. This lease has been under flood for 14 years. On this lease, certain physical difficulties resulted in wide variations in water pressure. The main pressure increase takes place from June to September, 1949. On this lease, there was no noticeable relation between the pressure changes and the number of leaks in the pressure system. Likewise, there was no definite observational relationship between the date of pressure change and the number of wells pulled. It could be argued, however, that there were some additional wells pulled as a delayed effect of the pressure increase. The marked increases in oil production at two definite periods in 1948 are due to other causes. Insofar as is known, however, the increase in oil production in 1949 was directly due to the pressure that was increased from June to October of that year. The plant pressure was increased from 800 to 950 lb, which is an increase of nearly 19 per cent. The sand-face pressure increased from 1250 to 1400 lb or 12 per cent. The water intake rate increased 16.2 per cent after the pressure increase. The oil production rate increased 16.5 per cent. The total cost for energy (gas and electric) increased 7.7 per cent per month. As the cost of energy

†Presented at the spring meeting, Eastern District, API Division of Production, Columbus, Ohio, April 3, 4, 5, 1951.

[1]Parke A. Dickey and John F. Buckwalter, "Secondary Recovery of Oil in the United States," Second Edition, American Petroleum Institute, 1950, Pages 344 to 349.

[2]Joseph W. Breston and Richard V. Hughes, "Range Between Pressure and Recovery in Long Core of Water Flooding," TP 2591, American Petroleum Institute, Journal of Petroleum Technology, Volume 1, No. 4, 1949, Pages 100 to 110.

*Quaker State Oil Refining Corporation, Bradford, Pennsylvania.



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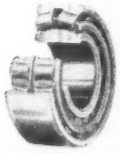

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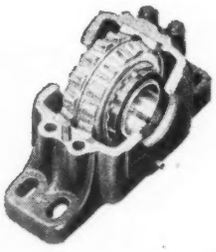

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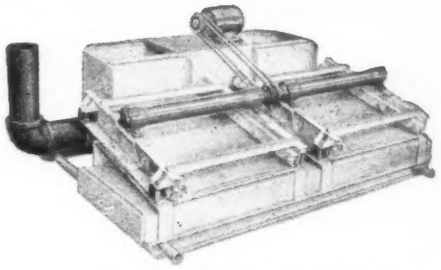

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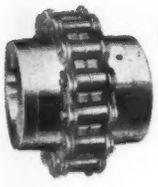

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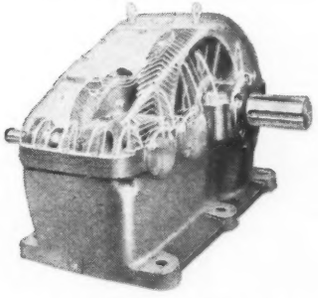

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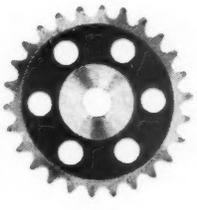

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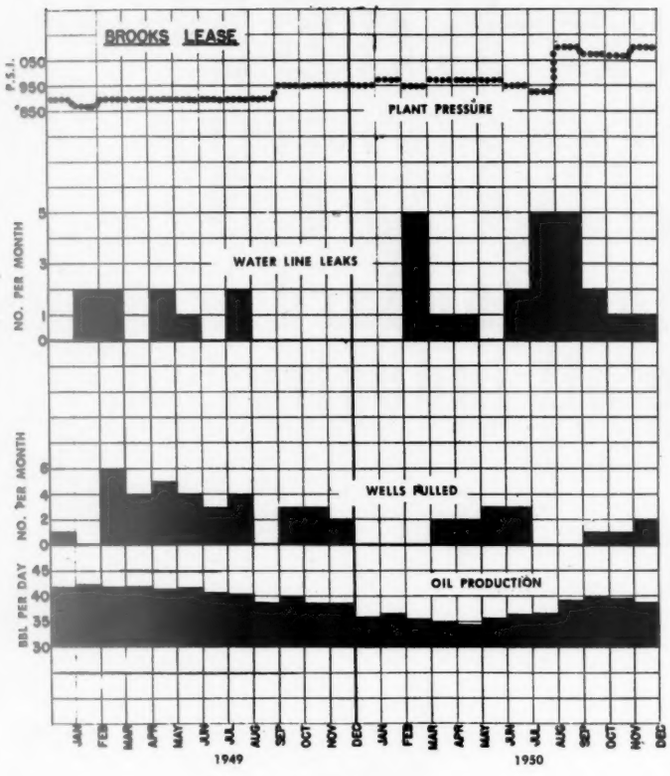

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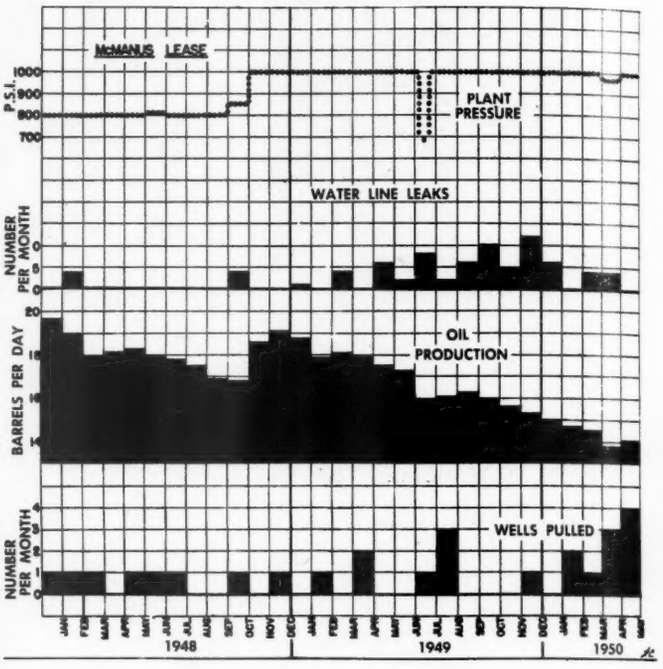

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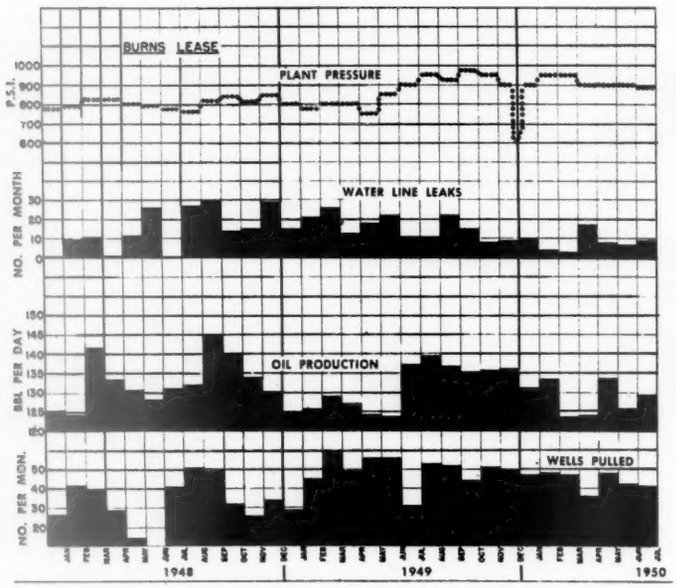

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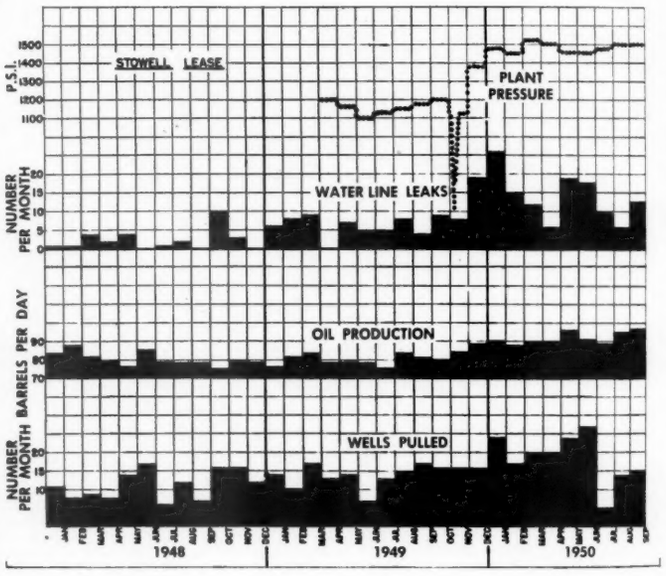

represents 29 per cent of the total direct operating cost on this lease, the over-all increase in cost was only 2.2 per cent per month.

Fig. 3 shows similar information for the McManus lease also situated in the Bradford field in Pennsylvania. This lease had been under flood for four years prior to the pressure increase in October, 1948. There was no reflection of the increase in pressure in either the number of water line leaks or the number of oil wells pulled on this lease. This is a small lease permitting a very close control of all operating conditions. In the middle of 1949, there was a mechanical failure of the pressure pump resulting in the pressure plant being shut down for three days. A study of the oil production rate shows a marked drop extending over approximately sixty days. Quantitative study indicates a loss of 5 per cent of the total oil production for this period. Three days out of sixty also represent a stoppage of pressure for five per cent of the period. There is no evidence from the oil production curve that any of this lost oil has been recovered to date.

As shown on the graph, the plant pressure was increased from 800 lb to 1000 lb which is an increase of 25 per cent in energy required. The sand-face pressure increased from 1290 lb to 1490 lb which is an increase of 15.5 per cent. The water input rate as shown by individual well meters, increased 23 per cent;[3] the rate of produced oil increased 20 per cent as of the second month after the pressure increase. The gas and electric service on this lease is combined with other installations. Calculated from the energy demand given above and using a figure of 20 per cent as the portion of the lifting cost due to energy requirements; we arrive

[3]It should be pointed out that there is considerable difficulty in getting individual meters to accurately record the water injected.

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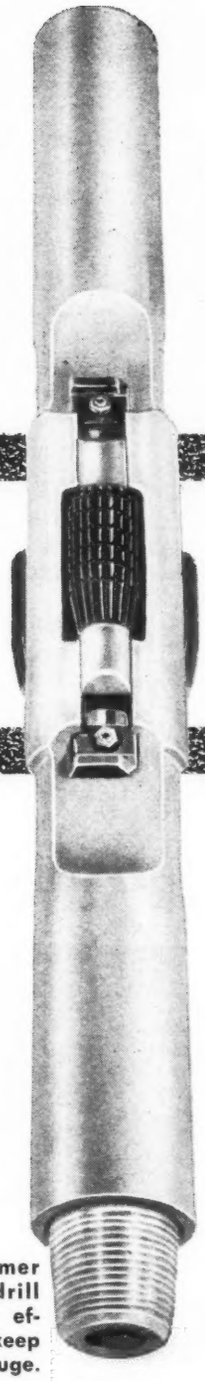

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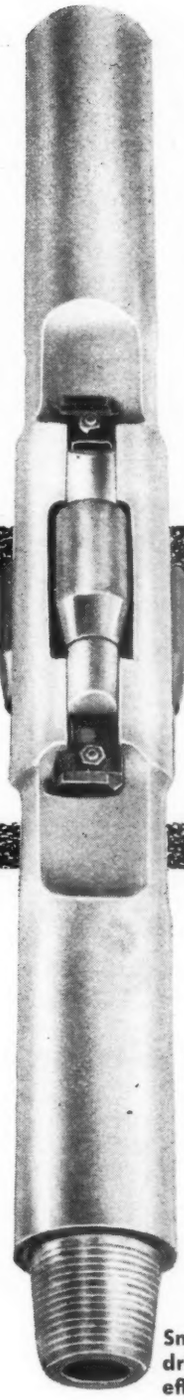

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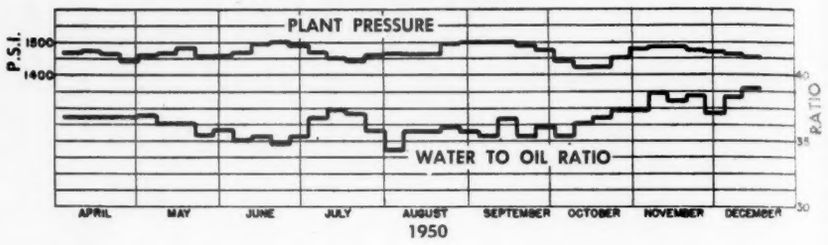
at an over-all increase in lifting cost of five per cent because of the pressure increase.

Fig. 4 shows similar information for the Stowell lease also located in the Bradford Field in Pennsylvania. This lease has been under flood for a period of twelve years prior to the pressure change in December, 1949. On this lease, there was a direct reflection of the pressure change in both the number of leaks in the water lines and in the number of oil wells pulled. A study of the figure indicates that the number of water line leaks have, however, returned to a level that would be expected in the over-all trend. Although the number of wells pulled did not drop as quickly after the pressure increase as the water line leaks, it was evident that here too, the number of wells pulled is declining to a rate similar to that prevailing prior to the pressure change.

FIG 5. STOWELL LEASE.



An attempt was made to obtain figures on the cost changes connected with the pressure increase on this lease. Unfortunately, there were numerous other changes made on this lease at about the same time as the pressure increase. It does not appear to be feasible to attempt to separate the figures. The changes made on this lease involved a complete revamping of the pressure system and it appears probable that the expense of the changes was considerably higher than shown for the other leases.

Water-Oil Ratios

While the foregoing discussion largely answers the various points raised in the introduction, it was felt that additional supporting information was needed with respect to Item 3 relative to the water-oil ratios. The metering or measurement of the water produced on any lease presents many practical complications. The method finally adopted was the use of recording floats with V-notch weirs.

Weirs were installed on the Stowell lease a few weeks before the major increase in plant pressure in 1949. Unfortunately, there were various reasons why the readings during this early period were not considered reliable. The increase in fluid produced necessitated a change from a 6-day pumping schedule to a 7-day pumping schedule. Several wells were cleaned out about the same time. In addition, considerable mechanical trouble was experienced with the weirs. Rapid build-ups of paraffin and scale on the weir notches were particularly troublesome. It was not until April, 1950, that conditions were finally stabilized sufficiently to obtain usable measurements.

Fig. 5 shows the plant pressure on the Stowell lease plotted with the produced water-oil ratios. In plotting the information, it was found that it was necessary to average both the pressures and the produced water-oil ratios. The method used was to average three weeks' readings and plot as one in what is known as a "roll" average. For example, Weeks 1, 2, and 3 were averaged and plotted as No. 1. Weeks 2, 3, and 4 were averaged and plotted as No. 2. Weeks 3, 4, and 5 were averaged and plotted as No. 3. Toward the end of June, 1950, there was a progressive decline in pressure. The resulting water-oil ratios in July increased materially. The pressure was increased in August and more particularly in September. As a result, the water-oil ratios appeared to decline. A drop in pressure in October resulted in a rapid increase in water-oil ratios. A better average pressure in November apparently held or reversed this trend.

Fig. 6 shows similar information for the Brooks lease. Here, the major pressure increase occurred late in August, 1950. There was a marked reduction in the water-oil ratios occurring in September. A drop in pressure in the latter part of September and early

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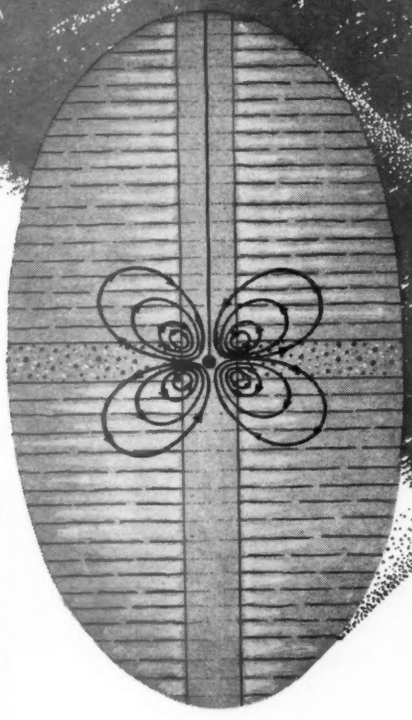

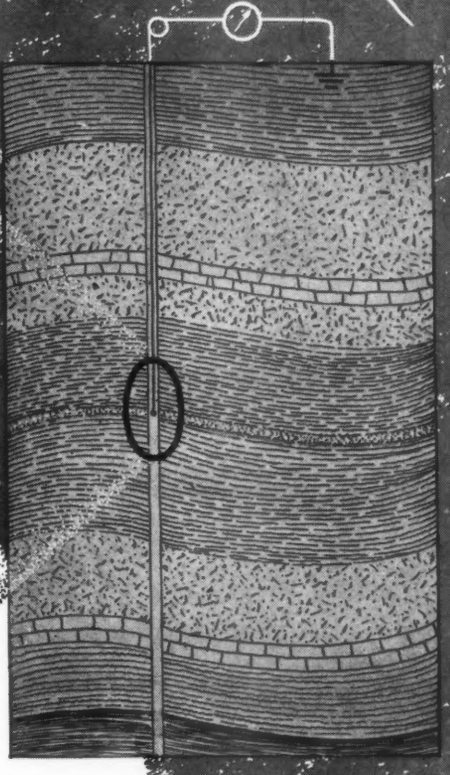

The spontaneous drill hole potential in and around a permeable bed results in the current distribution shown in the above schematic drawing.

Benjamin Franklin performed a famous experiment 200 years ago, which had a counterpart in the investigations of ground potentials carried on much later by the Schlumbergers. Franklin proved the existence of positive and negative electrical charges by flying a kite in a rainstorm.

This early experiment in the field of natural electrical potentials encouraged other investigators to start and continue work of increasing practical value. The measurement of ground potentials in bore holes by the Schlumbergers was one such important development. The resulting spontaneous potential curve was added to the already existing resistivity curve to complete the fundamental Electrical Log. The development, now only twenty years old, has had an increasing influence on oil exploration and production.

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October resulted in an increase in water-oil ratios. Similar results were obtained on later pressure changes. It is well to point out again that the method of averaging used trends to smooth out minor irregularities. It is felt, however, that the general trend shown is valid.

Summary

The limitations of field data should always be kept in mind in any studies of this type. Usually there are several factors that can give similar effects. It is necessary, therefore, to look at the over-all trend and to consider a sufficient number of cases. The writers do not claim that the data presented herein are conclusive. However, the following summary appears to be justified.

1. Pressure increases on old leases may result in an increasing number of leaks in the pressure system for any given period. In the cases studied, however, the rate of occurrences of leaks seem to decline rather quickly to the level prevailing prior to the pressure increase.

2. For the leases studied, the information was not conclusive with respect to the number of oil wells that needed to be pulled. Three leases showed no change.

3. Insofar as could be determined on two of the leases, not only was there no increase in water-oil ratios as a result of presure increases; but, on the contrary, there was distinct evidence of a decrease in water-oil ratios. These are the most surprising results to come from this study. If these findings are substantiated by further tests, it appears to the writers that it is very strong evidence that higher pressure gradients will result in a higher ultimate recovery of oil to any given water-oil ratio.

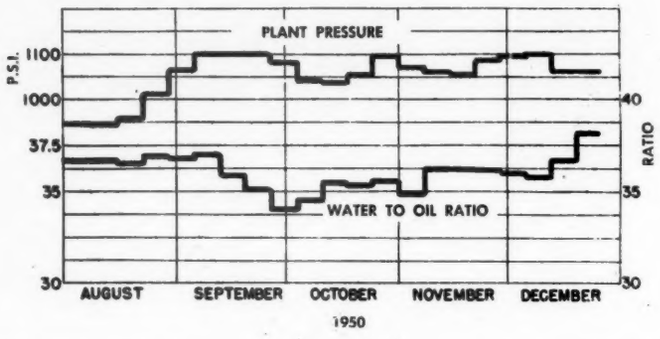
4. Actual cost figures on two leases indicated that the increased costs due to the pressure increases were of the same magnitude as expected. The total increase in cost, however, was quite low.

Acknowledgments

Results such as those compiled for this paper could not have been obtained without the full cooperation of the superintendents and field men on the leases involved. To all these, sincere thanks are due.

The entire engineering department of the Quaker State Oil Refining Corporation participated in these tests. Particular mention is due J. Kenneth Barton and Gerald F. Brown. John Buckwalter of the Ryder Scott Company aided by reviewing the paper. Thanks are due the Quaker State Oil Refining Corporation for permission to publish these results. * * *

FIG. 6. BROOKS LEASE.



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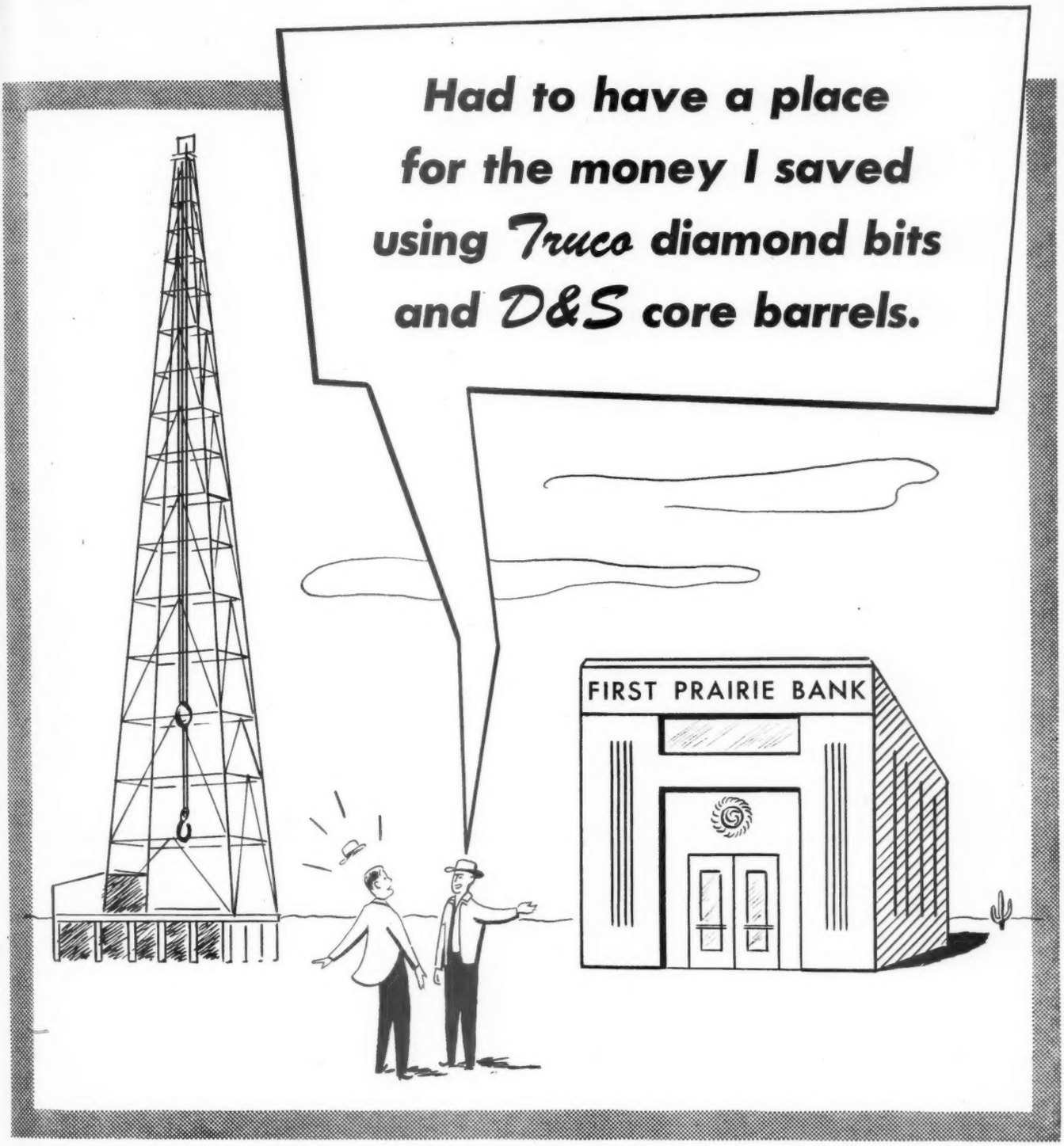

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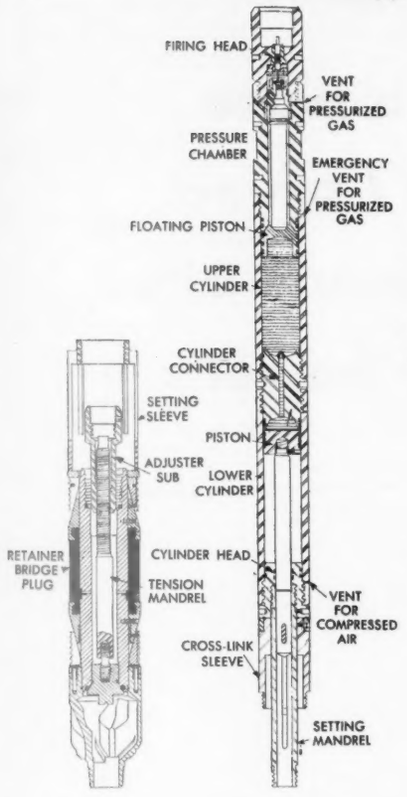
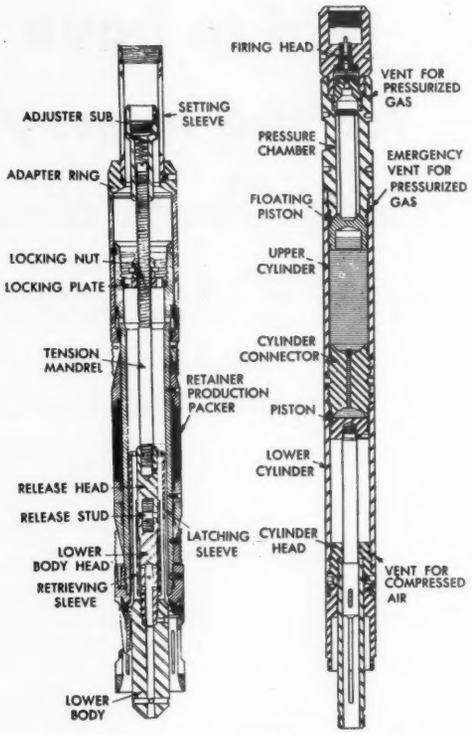


Retainer bridge plug. Wire line setting assembly.

FIG. 1.



Retainer production packer. Wire line setting assembly.

FIG. 2.

sequence to insure the successful setting of bridge plugs, production packers, or other tools that are run on it. A firing head is attached to the electric line and electrically ignites a filament-type igniter. (This is accomplished by mechanical means when the tool is run on a sand line.) The igniter, in turn, ignites the power charge (in the pressure chamber), which burns slowly and forms a gas that develops the necessary operating pressure. The pressure thus developed is transmitted by means of the floating piston through a hydraulic fluid to the working piston, thence through the piston rod to the cross link, which transfers the downward push from the inside of the pressure setting assembly to the outside, and thence down to the lower end, where it serves to set the upper slips of the tool being run firmly against the casing. When the upper slips are wedged against the casing so tightly as to permit the friction at this point to overcome the weight of the setting tool, the pistons will no longer move downward but will remain stationary, and the outside portion of the pressure setting assembly will start to move upward. This upward movement that is transmitted to the body or inner member of the tool being set will cause this portion of it to move upward, thereby setting the

The Wire-Line Pressure Setting Assembly As Used to Set Tools Having Opposed Slips†

C. A. GREVE*

THE wire-line pressure setting assembly was developed primarily to make available to the industry a means of setting tools having opposed slips in casing when run merely on the gun-perforating companies' electric lines or, where cable-tool operations are involved, on the sand line if desired. This unit affords a fast, safe, and economical method of setting tools of the opposed-slip type at any predetermined point in the casing. The development of the setting tool has an interesting history. Development work was begun in response to repeated requests from the field, and the work that followed before a practicable device was offered to the industry represents more than a decade of engineering, development, and experimentation. Several approaches to the problem were made. First, a spring-actuated type of tool was used. This was followed by a new setting tool in which forces were developed chemically. A great deal of work was done on this new tool and a number of variations were made before the development of the present tool. The question of a simple type of motive power presented a major problem and considerable time was spent in the development of the power charge, which is the motive power in the wire-line pressure setting assembly.

*Baker Oil Tools, Inc., Houston, Texas.

†Presented before the Spring Meeting, Southwestern District, API Division of Production, Beaumont, Texas, March 7-8-9, 1951.

Construction and Operation

This pressure setting assembly is primarily a device in which the products of combustion are utilized for gradually developing a force through pressure. This motive force operates the various working parts in proper lower slips and firmly packing off the packing element. As the pressure of the gas within the tool builds up (with the continuing combustion of the power charge) it reaches a point at which it is sufficient to part the release member. The parting strength of the release member is carefully controlled to insure a positive pack-off plus a reasonable margin of safety before the release member parts. Pressure in excess of 7000 psi is required to free the pressure setting assembly from the set tool. "O"-rings are used for sealing in all places where pressures are encountered.

The tool to be run is attached by means of the proper adapter to the pressure setting assembly, which, in turn, is attached to the gun-perforating companies' line, or to the sand line where cable-tool operations are involved. Correct "zero" point is es-

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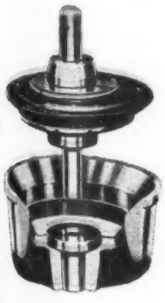

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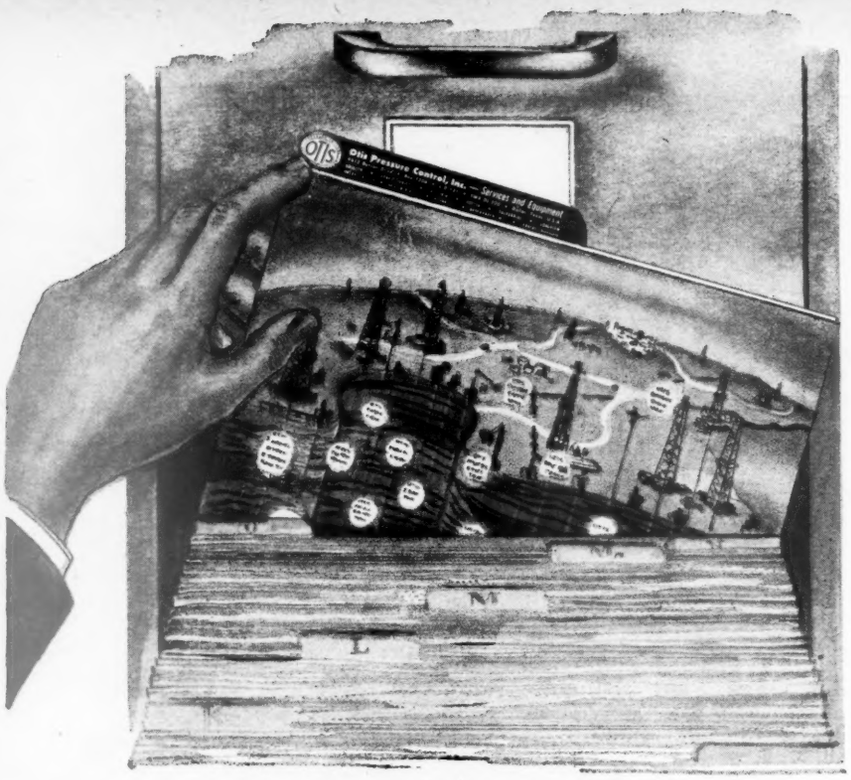

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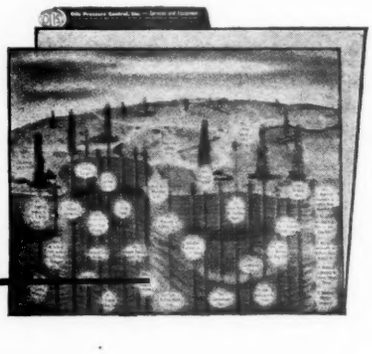

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tablished, and the entire assembly is run at a safe speed to slightly below the desired setting point, then picked up to the desired setting point. This procedure is followed in order to be sure that all of the stretch is out of the electric (or sand) line. The circuit is then closed. This causes the tool to set and the pressure setting assembly to release in a matter of seconds. The gun-perforating companies' trucks are all equipped with weight indicators, and a definite indication will be seen on the weight indicator when the tool is set. A loss of weight will show on the weight indicator during the setting of the tool, as the pressure setting assembly moves up the hole slightly during the setting operation. There is practically no recoil when the release member is parted, because the small orifice in the cylinder connector acts as an effective hydraulic dampener. No strain is imposed upon the electric line.

As soon as the release member is parted, the pressure setting assembly is removed from the hole, the internal pressure released, and the electric (or sand) line removed.

Advantages

When tools of the opposed-slip type are run on the wire-line pressure setting assembly, a distinct saving of time results in all cases where the depth of the setting point is a factor, inasmuch as this procedure eliminates a round trip with the tubing, which would be required if the tools were run on tubing or drill pipe. (The danger of premature setting is practically eliminated when the tools are run on the wire line. If any foreign matter sufficiently large to stop the tool is in the well fluid, loss of weight will be shown on the weight indicator immediately and the tool can be picked up. If the same thing should happen when running the tool on tubing or drill pipe, it is quite possible that sufficient weight could be applied before the downward travel could be stopped to cause premature setting of the tool.) Forces of up to 50,000 lb are exerted by the pressure setting assembly, the force being regulated by the size of the release member which is machined to very close tolerances. This insures that the proper amount of pull is exerted on each of the various sizes of tools set.

Other "down-hole" tools that can be run on the wire line pressure setting assembly are in the process of development; and, in time, these will take their place in the oil industry.

The pressure setting assembly connected to a casing bridge plug is shown in Fig. 1; the assembly attached to a production packer is shown in Fig. 2. * * *

THE WORLAND, WYOMING FIELD†

Unitization helped in efficiently producing this 10,000-ft field with its low reservoir temperature and high hydrogen sulfide gas

J. I. MORRIS*

On the basis of a structure indicated by reflection seismograph work, The Pure Oil Company assembled a unitized block of acreage in Washakie County, Wyoming during 1943. This block was designated the Worland Unit. The Worland field lies in the southern part of the Big Horn structural basin. The field is an anticlinal structure trending generally northwest-southeast and having approximately 1000 ft of closure in the Embar (Phosphoria) and approximately 700 ft of relief in the Frontier zone.

Geographically, the Worland field is in the north central part of Wyoming 9 miles north of the city of Worland. The majority of the area is under cultivation being irrigated with water from the Upper and Lower Hanover canals on the east and the Big Horn Canal on the west sides of the field. The northwest part of the field is in the semi-arrid "badlands" west of irrigation facilities. The Big Horn river flows through the field on the north-south trend dividing it into approximately an east and west half. Hard surface highways, U.S. No. 20 and a Wyoming state secondary, bound the field on the east and west. Railroad, telephone, electrical power, and sweet gas facilities are available in the immediate field area. Surface elevations are approximately 4000 ft and the annual precipitation of 10 in. does not cause appreciable interference from rain or snowfall.

Discovery

The discovery well, The Pure Oil Company's Worland Unit 1-E, was spudded in near the assumed crest of structure on June 11, 1945. A string of 7 in. casing was set at 10,242 ft near the top of the Tensleep sand on February 9, 1946. On March 12, 1946, the total depth of 11,379 feet was reached in the Big Horn dolomite. Cores recovered in the Embar (Permian) zone, a dolomitic limestone section, had shown indication of a slight gas show. In order to test this zone Unit 1-E was plugged back to 10,131 ft and was perforated from 9990 ft to 10,055 ft or through a 65 ft interval. A drill stem test was run on this perforated zone, however, it was necessary to discontinue the test after 13½ min because the toxic hydrogen sulfide gas endangered the lives of personnel present. The well was completed for a production test by running a production packer and 10,047 ft of 2½ in. tubing on March 21, 1946. Initial production tests indicated the well potential to be 165 bbl of 43.5 API gravity light green oil per day with a gas-oil ratio varying from 4900 to 15,000.

The possible complexity of operations in the field was immediately apparent when an abnormal decline in well productivity denoted mechanical trouble in the well. The running of a measuring line found the tubing to be plugged with hydrates. The accumulation was eventually drilled out with small wire line tools. This job, too, was further complicated in that new hydrates would form nearly as rapidly as the original were drilled out. Continued operations opened the tubing through approximately 2800 ft of hydrate accumulations.

The operators were now faced with a two-fold problem—the methods by which to produce these well fluids and the associated problem of adequately protecting personnel and property from the toxic gas.

The formation of hydrates in the tubing was reduced by the first installation of a hot fluid circulating system. The fluid used in the original system was water, however, the incorporate disadvantages of water in below freezing temperatures led to the adoption of oil as the circulating fluid. This installation demonstrated that the field could be produced commercially.

Although a major production problem had been corrected, continued tests encountered additional problems peculiar to a field of this type. Even after hydrate accumulation was alleviated by use of the hot circulating fluid, a black substance of an asphaltic base combined with foreign materials tended to plug the tubing. This material has been termed asphaltine by various parties. Production into the burn pit eventually cleaned the well. The failure of spring steel in conventional bourdon tube type gages presented a hazard around the well as these failures allowed escape of the gas. This trouble was corrected by using a gage in which the bourdon tube assembly was isolated from the well fluids by a diaphragm type protector. The tube assembly is blycol filled to the diaphragm in order to provide positive transmittal of well pressure.

While continuing production tests at Unit 1, failure of sub-surface material became apparent when well pressure entered the circulating system either through the packer leaking or a part in the tubing. The well pressure opened a crack in a hydraulic swedge nipple between the tree and valve on the circulating system thereby allowing a large volume of gas to escape to the atmosphere. As there was no immediate way to stop the leak, inhabitants in the vicinity were evacuated. In order to prevent further accumulation of the gas, tracer bullets from a high powered rifle were fired into a gas pocket at the well to set it on fire. Remedial operations were started immediately and the well was killed 17 days later. After workover operations were begun, it was found that the tubing had parted in a coupling 2449 ft from the surface. The well was placed on production in April 1947. Worland Units 2-E and 3-E had been successfully completed during this time so that development of the field was continuing.

*The Pure Oil Company, Worland, Wyoming.
†Presented at the spring meeting of the Rocky Mountain District, API Division of Production, Gladstone Hotel, Casper, Wyoming, April 19-20, 1951.

Development

The drilling rigs used in Worland were in general consolidated rigs with a rated depth capacity of 10,000 ft with 4½ in. drill pipe. The usual derrick was an 850,000 lb capacity, 30 ft base by 136 ft high.

The major drilling problem in the field has been with drilling fluid in an attempt to receive maximum drilling efficiency and reduce frequency of lost circulation.

Four general types of drilling muds were used with varied results, these being starch, lime, sodium carboxymethyl cellulose and caustic-quebracho. The various types were tried in order to secure a minimum loss of water and/or mud to the various porous formations, particularily the productive zones of the Frontiers and the Embar. This was especially detrimental in the Embar as cores showed mud blocking in the vugs and fractures. The most used mud was caustic-quebracho, as experience proved this to be satisfactory. To drill the Embar, it was endeavored to have the mud at a viscosity of 45-55 seconds, weight of 9.5, PH of 9+ and a water loss of 3-5 cc.

The upper portion of the Embar limestone presented the greatest loss of circulation problem. Although it did not occur in all wells, it was the case rather than the exception. It varied from a minor to a severe loss in that several wells took the volume of mud in the hole and a large portion of that available in the pits. Circulation was regained through the use of standard materials such as mica, ground cellophane, and shredded cane.

Loss of circulation in the Frontier formation was not of the magnitude encountered in the Embar and was corrected by the addition of small quantities of bulk material to the drilling fluid. Minor cases of loss of circulation were encountered in the lower part of the Cody formation; however, these were corrected through mud conditioning. Although loss of circulation constitutes a major problem in Worland, the most detrimental effect and seriousness of the problem arises from the mud reducing the permeability of the productive horizon rather than the possibility of a blowout or continued loss of circulation. In general, the loss of circulation problem in Worland is not as serious as that in many fields in the Rocky Mountain area.

Two types of well completions have been used in the Embar of the Worland field: The productive zone was drilled and 7 in. oil string was set on bottom and gun perforated for production; or the oil string was set in the top of the Embar before drilling into the pay section. Usually the setting of casing through the productive zone was occasioned by the desire to test zones below the Embar or in the belief that the gas-oil ratio could be better controlled through selective perforating. Wells high on the structure (Embar top at —5900 to —6200 ft) had a tendency to produce oil of 37-45 API gravity at a gas-oil ratio of 5000 to 18,000 cu ft per barrel. Lower wells (—6200 to —6600) produced oil of API gravity ranging from 20 to 38 deg and gas-oil ratios between 1500 and 4500 cu ft per barrel. Production history did not indicate that selective perforating materially affected the producing gas-oil ratio. As there were no other apparent advantages, the majority of the wells were completed with the oil string set from 2 to 5 ft into the Embar limestone.

The possibility of hydrates forming in the drill pipe plus the inherent danger of escape of hydrogen sulfide during the test and while the tool was being pulled precluded much use of drill stem tests.

The necessity for a hot fluid circulating system in completed wells was demonstrated in operations at Unit 1-E. This involved isolating the circulating fluid from the well fluid by setting a production packer in the bottom of the oil string. Approximately 3200 ft of 5 in. casing were swung in order to provide channels for flow of the heating fluid which acted to heat the tubing to a depth required to avoid hydrate formation. Procedure after running the 5-in. casing, and tubing, was to displace the mud with fresh water to which was added a formaldehyde solution as an inhibitor against corrosion from well fluids. The water was displaced with oil for use in the hot oil circulating system. Well head connections were made and the tubing was landed in the packer to complete the mechanical procedures necessary to produce a well. Wells that did not flow naturally were swabbed in. Frequent failure of sand lines that had been in contact with sour well fluids, led to the use of galvanized lines and treatment of these lines in corrosion preventive organic compound bath. After the final pull of each day, the line was passed through the bath and laid out over-night rather than being spooled. The failure of sand lines and associated wire lines has been so severe that some service companies refuse to run their wire lines in wells producing appreciable amounts of sour fluids.

The acidization of limestone has been effective in increasing productivity of Embar wells. The normal procedure was an initial treatment of 5000 gal of 15 per cent hydrochloric acid containing emulsion breaking, surface tension reducing, and corrosion inhibiting agents, followed by a 15,000 gal treatment of the same type acid. These quantities are average values as some wells were acidized with as little as 3000 gal, and others, with as much as 50,000 gal.

Maintenance and supervision were complicated by the fact that the Big Horn river separates the east and west sides of the field. There was no bridge in the immediate vicinity; consequently, an 18 mile trip by road separated the two areas. Bridges are situated at Rairden north of the field; and Worland, south of the field—the distance being approximately the same either way. As development continued simultaneously on both sides of the river, a camp and a stock point were established on each side. An FM radio network was installed to assist in control of field operations and to provide an emergency communication system. Transmitting and receiving sets were placed at the field production office, cars, and residences of supervisory personnel, rotary drilling rigs, and in switchers pickups.

Earthen dikes and pipe stanchions were placed around wells, tank batteries and production facilities in the river bottom to protect these installations from river ice in the event of an ice jam.

System Heaters

The most economical and efficient method of reducing the detrimental hydrate formation in well fluid flow facilities was the application of heat. The hot oil circulating system furnished heat to the well tubing and flow line heaters transfer heat for surface installations.

In the hot oil circulating system, electric motor driven reciprocating or centrifugal pumps take suction from a 30 bbl galvanized steel surge tank and discharge through indirect heaters to the well head. Oil from the annulus returns to the surge tank. In the 1,500,000 Btu per hour rated capacity indirect heaters, the temperature of the circulating oil is raised as high as 180 F. In order to allow a minimum heat loss lines from the heaters are insulated and/or buried. The circulation movement of hot oil in the annulus transfers heat to the fluid being produced. Flow is down the annulus between the 2½-in. tubing and 5-in. casing and up the annulus between the 5 and 7 in. casing. Temperature drop between the well inlet and outlet of this system varies from 35 F to 75 F.

A check valve is installed on the circulating system inlet line, and an ex-

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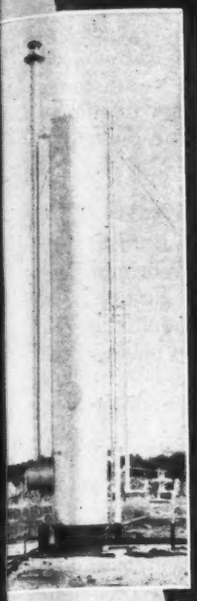

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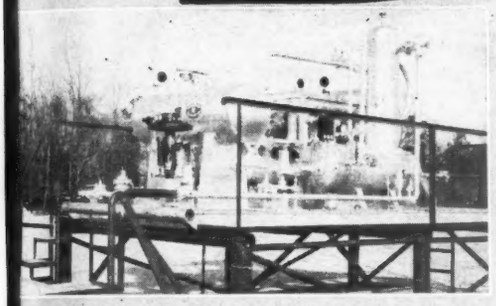

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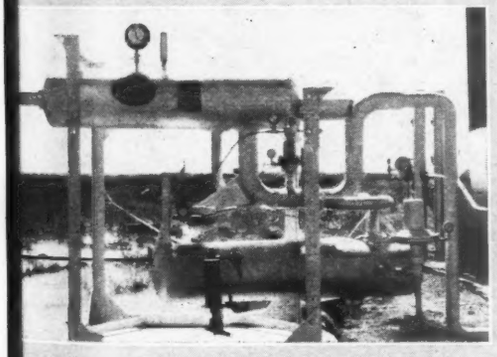

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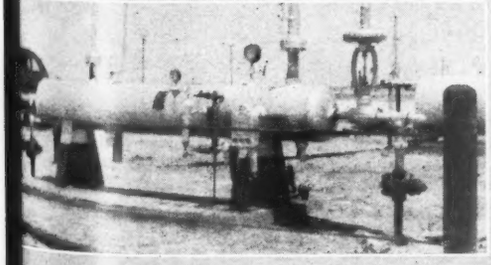

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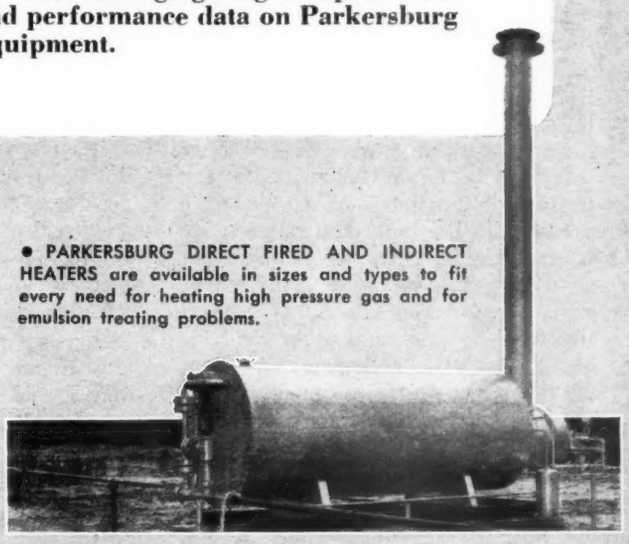

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cess pressure shut-in valve on the outlet line to prevent well fluids from escaping through this system in the event of a packer or tubing failure. These valves and pipe on the well side are of design specifications capable of withstanding well pressures. The pump is protected from operating against a closed discharge by a pressure relief valve that allows discharge into the suction.

In the flow line hook-up that was used while producing into tank batteries during the first period of operations, tubing head pressure was reduced to first stage separation pressure through four adjustable chokes at the indirect heaters. Pressure drop was taken at these points in order to maintain well fluid temperature above the hydrate point. These 1,150,000 Btu per hour, high pressure two pass heaters supplied additional heat to keep the fluid above the hydrate temperature during three stage separation. First stage separation was at approximately 250 psig and the second stage was at about 50 psig. The separators were conventional 2½ ft by 12 ft 480 psig working pressure units. A third stage 20 in. by 34 ft shop made unit operated at two ounces pressure.

Tank Batteries

To avoid transporting well fluids unnecessary distances, individual tank batteries were installed for most wells in the first period of operation. Where proximity of offset wells made separate batteries impractical, first stage separators were operated at well locations prior to movement of fluids to the consolidated tank battery. From two to six bolted, 1000 bbl, galvanized steel stock tanks were contained in these batteries.

The vapor system on Worland tank batteries was designed to serve a three-fold purpose: Prevent escape of toxic gases to the atmosphere; reduce losses in oil gravity and volume through maintenance of a two ounce pressure in the tank, and prevent air from entering tanks by maintaining a sweet gas blanket. A district fuel gas system distributed purchased sweet gas for this and other field requirements. By excluding air from the tanks, the possibility of a tank explosion from spontaneous ignition of iron sulfide was minimized.

The two way valve on the vapor outlet connection from each tank was normally open to the main vent line on which a regulator maintained a two ounce back pressure. A sweet gas supply regulator that was set for approximately 1¾ ounces fed sweet gas into the main vent line at times when tank pressure dropped below the two ounce sour gas venting pressure.

Before opening the thief hatch to gage a tank, pressure in tanks was reduced by operation of the two way valve lever, which closed the main vent line and opened the sour gas bypass line. This isolated the tank and minimized the escape of vapor from the tank when the hatch was opened. As a further precaution, the hatch cover cannot be lifted until the valve is opened to the by-pass line. Proper operation of the system was checked by the manometer installed near the hatch.

The shop made separator further reduced gassing in the tanks by venting directly the vapors that came out of solution when the pressure was reduced from 50 psig to 2 oz. Oil from this unit gravitated to the stock tank.

In order to allow additional protection for personnel working around tank batteries, tank walkways were provided with double stairways to permit exit from either end. Field regulations require that any person going onto a tank walkway must wear a gas-mask and that a second party equipped with a gas-mask remain at the fire wall. Consequently in the event of an emergency, help was available immediately. As the chance for survival after being gassed by hydrogen sulfide is a direct function of the time of exposure to the concentrated fumes, immediate evacuation from the contaminated area is of the essence. The standard oil field cannister type mask did not prove satisfactory as it is effective against a maximum hydrogen sulfide content of 2 per cent. Although oxygen generating cannister type masks have been used and are available for an extreme emergency, their effective use was limited in that several breaths in uncontaminated air are required to start oxygen generation, the unit is bulky; and once the expensive cannister is opened, it cannot be used intermittently over long periods as the chemicals deteriorate in a short time.

The fresh air type mask was adopted and has proved satisfactory for all usage. Air is provided to the face piece through a reducing regulator from a high pressure cylinder that is mounted on a harness carrier so the cylinder is carried on one's back. A pressure gage warns the user when the air supply is reaching depletion. Small individual cylinders are filled from three major fresh air cylinder batteries in the field.

Two complete mask units are assigned to each switcher pick-up truck. Each switcher is furnished with a personal face piece. Resuscitator units are maintained at the same locations as the fresh air batteries. Oxygen therapy units, gas masks, face pieces, cleaning solutions and replacement filters are kept at switchers' doghouses. Personnel are further guided by safety instructions.

Material Failures

Various types of equipment have failed in service in the Worland field; however, these failures cannot be attributed only to corrosion from sour well fluids. Rather, it is believed that the failures are caused by a combination of causes such as hydrogen embrittlement, stress caused by extreme temperature change, cold embrittlement and hydrate formation around movable parts.

The failure of tubular goods has caused a great deal of trouble and expense to operators. This type failure was indirectly responsible for the fire at Unit 1-E; and failures in other wells have necessitated work-over jobs and prolonged rig time.

Although the majority of breaks have been in tubing couplings, a series of failures occurred in one 5 in. circulating string. These failures varied from open breaks to lines of cleavage along the plane of the tubing. As many as 8 specific breaks have been found in one 10,000 ft string of tubing. Additional failures have occurred in surface flow lines where tubing is used between the well and heaters. Repeated laboratory investigations of broken pipe have failed to reveal active corrosion and no definite conclusions have been drawn as to the cause. The combined effects of thermal stress induced by the circulating system operation, and probable hydrogen embrittlement cannot be disregarded as a possible cause, however. Tubing was made up with jaw tongs in the early days of the field and it was believed that tong marks could be the origin of some failures. Friction tongs were adopted for use to eliminate this possible cause of trouble.

An excessive amount of breakage occurred in stems of well-head gate valves. It was believed that this was the result of the factors mentioned. Stainless steel alloy valves were used in an attempt to alleviate this situation; however, some breakage of alloy stems still occurs. The field procedure of applying heat from a portable steam generator to inoperatable valves has further reduced breakage. This procedure is particularly adaptable in cold weather when atmospheric conditions tend to aid hydrate formation.

Failures of wire lines, gages, and steel springs have been discussed previously.

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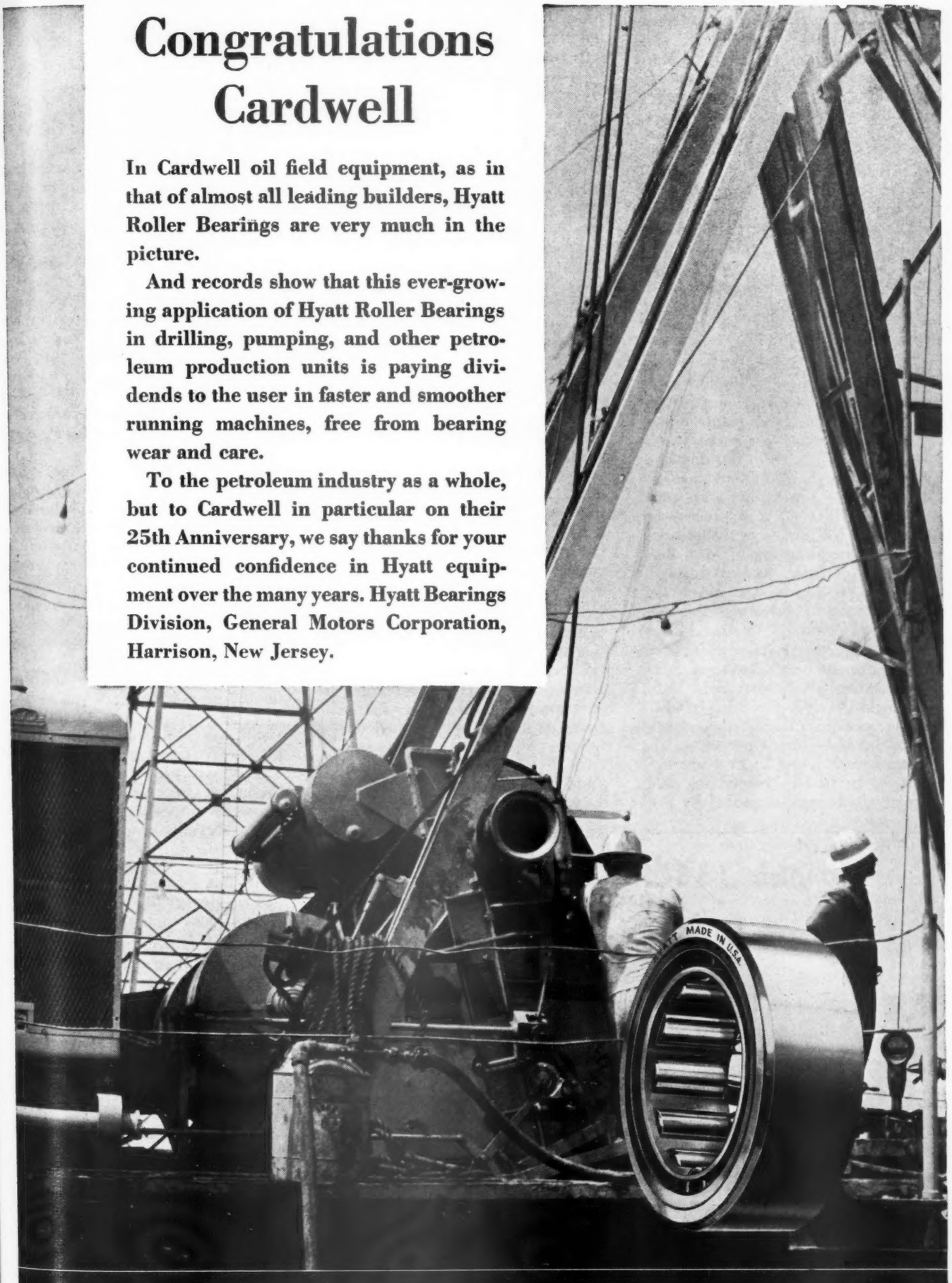

HYATT ROLLER BEARINGS

Gas-Oil Gathering System

The main lines of the gas-oil gathering system were geographically situated so as to require a minimum number of laterals and where necessary, provide minimum length laterals. To facilitate this design, the system was broken down into an east and west leg with a junction near the gasoline plant. Operationally the line was designed for a pressure drop of 5 psig per mile when either leg was conducting a sufficient quantity of gas and oil to load the plant. This resulted in main line sizes varying from 5½ in. to 16 in diameter. The system is of all welded construction, coated and wrapped and provided with cathodic protection.

The line was laid to grade as near as possible to minimize liquid accumulations and consequent uneven gas volume delivery to the plant. Winter subsurface temperature surveys indicated the desirability of burying lines with a minimum of 5 ft coverage. To arrive at this coverage in the irrigated section of the field it was necessary to dragline the ditches as the high water level caused caving of work done by a conventional ditcher. Specially cast concrete blocks were positioned on 10 in. and larger pipe in this area to prevent possible floating.

Pipe failures occurred on two extensions to the original system. After withstanding a 750 psig cold water test, leaks developed in 7 in. OD J-55 casing sections placed in service at considerably lower pressures. The failures were found to be transverse splits ¼ in. to 1 in. behind the weld. Repair welds were annealed by post heating. Several additional weak spots were found by testing the line with hot water at high pressures.

A suspension bridge having a 360 ft span was erected across the Big Horn River to serve as a combination foot bridge and pipe line crossing. The exposed portions of the 13⅜ in. OD Embar system on the west side earthen fill and on the bridge are insulated with hair felt and roofing paper. From an expansion bend on the east side of the bridge, the line loops down to below ground level and continues on an up grade to the plant. This is the main exception to the grade of the system.

Trouble with hydrate plugging has occurred in the system. Before the crude stabilization plant was in operation, attempts to move gas alone were generally unsuccessful because of hydrate plugging. This in part could have been the result of some water remaining in the lines after testing and the necessity to backfill a part of the ditch with frozen ground. The line was not kept continuously open until oil was brought in with the gas. Later plugging has occurred in temporarily dead sections of the system where block valves apparently permit some gas to leak by.

A pressure relief valve set at 400 psig with discharge to a flare is provided on each leg of the system. Individual wells are protected with pilot operated valves that will close with excess system pressure and check valves to prevent back flow to well.

So that individual well production could be determined, flow lines from the well were connected for direct flow to the gathering system, or flow through the separator, meter runs, recombined line, and into the gathering system.

Plant Operations

An agreement was made between The Pure Oil Company and The Texas Gulf Sulphur Company whereby Pure would deliver sour gas produced from the Embar reservoir to a plant to be built and operated by TGS for the recovery of commercially pure sulfur from hydrogen sulfide gas. The sweetened gas would be returned to a conventional absorption plant to be built and operated by Pure for recovery of LPG's and natural gasoline. Through an agreement with Montana Dakota Utilities, available residue gas from this plant was purchased for their distribution system. The Embar gas-oil gathering system was constructed as the service flow line for the Pure and TGS plants.

The installation of this system marked the major change in producing operations because upon completion of the plants, oil was no longer recovered in well tank batteries. Instead, wells were produced directly into the gathering system operating line to separators at the gasoline plant, nominally at 325 psig. The oil and gas were moved together in a common line to separators at the gasoline plant. The gas from these separators made up the high pressure steam to TGS. The oil went directly to the crude stabilization section of the gasoline plant, which serves to remove hydrogen sulfide from the oil leaving essentially a sweet oil; recover as liquid hydrocarbons those light ends that would normally be lost in atmospheric storage; and treat oil to pipe line specifications. The stainless steel lined crude stabilizer tower operates at 140 psig and is 48 in. in diameter by 67 ft high. The stabilized crude is run to central storage facilities for later transportation to refining centers. Gas from the stabilizer makes up the low pressure stream to TGS.

The high and low pressure sweet gas streams returning from TGS are processed directly in 250 psig and 60 psig absorbers at the gasoline plant for recovery of natural gasoline and LPG's. Available residue gas from the high pressure stream goes to the MDU compressor plant for boosting to northern markets. Residue gas from the low pressure stream is used for field fuel requirements.

Unitization

During the first period of operation four operators, Pure, Trigood, Sharples, and Carter, partially developed their leases and were obligated to drill and produce offset wells that

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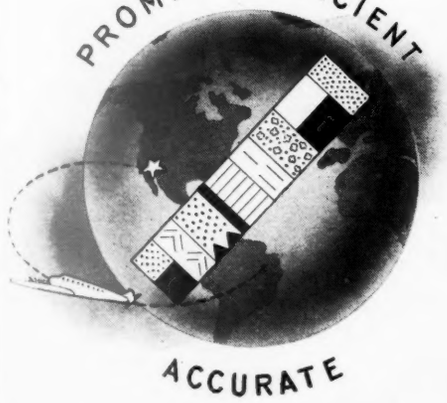

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were not structurally located to recover oil at the lowest gas-oil ratio. It was realized that unitization was the only solution that would allow selective production of the field to secure maximum oil recovery. Consent of all working interest owners and royalty owners was obtained; and working agreement permitting total unitized operation of the field and gasoline plant with The Pure Oil Company as operator became effective May 1, 1950.

Since this time the daily production from the field has been restricted to the quantity of oil which can be produced with 30,000,000 cu ft of sour gas, which the sulfur plant is designed to process.

Frontier Development

Three high gas-oil ratio wells of the Embar zone have been recompleted and a fourth well completed in the Frontier zone in order to bring the residue sweet gas sales to contract volumes.

Early production tests on a recompleted well showed hydrates forming in the tubing. Consequently, the same type hot oil circulating system and flow line heater arrangement used on Embar wells is used on Frontier wells.

As Frontier gas is free of hydrogen sulfide, it is not necessary that it be processed by TGS. A central Frontier gathering system with line sizes varying from 6 in. to 10 in. in diameter was constructed to conduct well fluids from wells to a three stage separation battery at the gasoline plant. A 1500 psig working pressure separator permits delivery of gas direct to MDU at a pressure sufficiently high for direct transmission. As this gas cannot be processed, this separator is usually by-passed and the incoming stream separated at 275 psig so that the gas may be processed in the high pressure absorber. Liquids from this stage pass to the next stage of separation operating at approximately 75 psig so that this gas may be processed in the low pressure absorber. Condensate is moved to the Frontier storage area adjacent to the Embar storage area.

Bottom Hole Pumping

Two Embar wells have been placed on the pump with one pump set at 6000 ft and the second at 7000 ft. One conventional beam unit and one air balanced unit is in operation. Standard high tensile strength sucker rods are used. Both stainless steel alloy and regular steel pumps have proved satisfactory. To date no evidence of active corrosion has been found in any of the equipment in contact with well fluids. The major trouble has been with the well head stuffing boxes. As it is necessary for the well to pump against 325 psig, these boxes must retain the pressure while allowing movement of the polished rod. This has resulted in abnormal wear on stuffing box rubbers requiring numerous replacements. Some control is obtained through special care in the alignment of the polished rods and repeated checking of same.

Conclusion

The development and operating of the Worland field have been complicated by the relatively high percentage of hydrogen sulfide present in produced gas and the hydrate formation resulting in part from low reservoir and surface temperatures. As these problems have arisen, operators have met them with satisfactory solutions. Although the field cannot be termed a normal oil field, it has been operated with certain required ramifications, as any other oil field producing from 10,000 ft would have been.

In keeping with the policy of utilizing all natural resources, unitization of the field provided a means by which all reservoir withdrawals could be used in producing marketable products.

* * *

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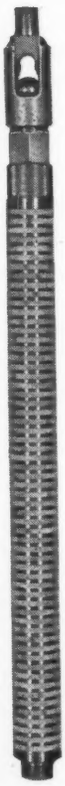

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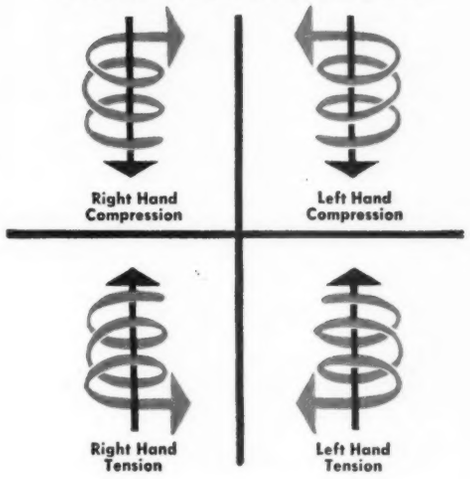

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A Baash-Ross Production Safety Joint placed in your tubing string provides a positive means of freeing the string at the point where the Safety Joint is installed, thus permitting important savings to be made in production operations. For example . . .

▶ Where production packers are used, a Safety Joint should be installed above the packer to permit positive and complete release of the tubing string should the packer become stuck.

▶ Where sanding conditions exist, one or more Baash-Ross Production Safety Joints should be installed in the tubing string to permit selective release and maximum recovery.

▶ Where it may be desirable to change production methods in a well, a Baash-Ross Production Safety Joint should be installed in the tubing string to permit such changes to be made quickly and easily without disturbing the packer.

Baash-Ross Production Safety Joints are simple in design, positive in operation and low in cost. They are provided with a unique locking lug that permits heavy rotational loads to be transmitted through the Joint without loosening it—yet disengagement can be quickly made whenever desired by merely following a simple sequence of operations. A choice of *four* different releasing actions is available—either *left* or *right* hand rotation, combined with either *raising* or *lowering* the production string—thus providing the exact releasing action best suited to each production hook-up.

LEAK-PROOF SEAL . . . FULL OPENING PASSAGE

Note in the illustration how the Baash-Ross Production Safety Joint is packed off top and bottom with self-sealing "O" rings to permit circulation through the Joint without leakage. Also, the Joint is full-opening so that rods, tools and clean-out equipment can be passed without difficulty. In fact, the Joint has the same internal and external diameters as the production string itself. Anything that will pass through the tubing string will pass through the Joint . . . and the Joint itself will pass through anything the tubing couplings will pass through—an important consideration when used with certain types of suspensions.

A Size For Every Production Need

Baash-Ross Production Safety Joints are made of heat-treated alloy steel and are available in all four releasing actions to fit all sizes and types of API Tubing. So no matter what the nature of your particular production operations, you can protect against costly recovery or conversion operations by placing one of these efficient joints on every tubing string.

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Here's how the Baash-Ross Production Safety Joint operates to protect your tubing strings. The Joint consists essentially of a box and pin releasing thread (either right or left hand, as ordered) that is packed off top and bottom with self-sealing "O" rings. In the upper portion of the pin thread, two vertical lugs are machined into the body, and these lugs mate with a corresponding lug machined into the box portion.

The releasing threads are cut with a loose fit—that is, when the Joint is made up, the two portions can move a short distance longitudinally with respect to one another without affecting the vertical alignment of the Joint. This movement permits the mating lugs to lock and unlock as one portion of the Joint is moved with respect to the other portion—and the design of the lugs determines whether the Joint unlocks in tension or in compression. A shear pin is also provided that permits longitudinal movement of the Joint, but prevents premature rotational release.

Basically, the releasing action consists of first unlocking the lugs by lowering (or raising) the string—then rotating the string in the proper releasing direction (either right or left) to sever the shear pin and unscrew the Joint. Only by first moving the string in the proper vertical direction, then rotating it in the correct releasing direction, can the Joint be disengaged—and by properly selecting the releasing action, other tools below can be set and released without risk of disengaging the Joint.

Prediction of Corrosion in Oil and Gas Wells†

So complex is corrosion behavior that the engineer must understand all possible methods in order to choose wisely

D. A. SHOCK* and J. D. SUDBURY*

Abstract

Using the techniques and fundamental data developed by the corrosion studies in high pressure condensate wells, the prediction techniques and evaluation methods have been extended to oil well corrosion. Internal corrosion in both oil and gas wells is believed to be due to the acidity developed in the water phase. The acids found and an evaluation of their corrosive behavior are discussed. The variable factors influencing corrosion rates are also discussed. In light of the action of the various corrodents and variables, the utility and limitations of the various prediction schemes are presented and a recommended plan of corrosion evaluation is set forth.

The Authors

D. A. Shock, senior research chemist in Continental Oil Company's production research laboratory at Ponca City, Oklahoma, previously served on the research staff of the University of Texas at Austin. In that capacity he was in charge of corrosion research problems including those sponsored by Natural Gasoline Association of America. Before his work at the University he was employed by International Minerals and Chemical Corporation, Austin, Texas, and Dow Chemical Company, Midland, Michigan. He is a graduate of Colorado College, Colorado Springs, Colorado, and obtained his masters degree in chemistry from Texas University.

J. D. Sudbury is a research chemist in Continental's production research laboratory. He received his B.S., M.A., and Ph.D. degrees in chemistry from the University of Texas. He served two years in the U.S. Navy from 1944 to 1946 and joined Continental Oil in 1949.

Introduction

Corrosion in oil and gas wells, other than in sour crude areas, had received little or no attention before 1945 and 1946. The severe corrosive attack noted in high-pressure condensate wells about that time initiated considerable study of internal corrosion problems. The greater portion of this work applied specifically to gas condensate corrosion. In the past few years, however, it has become increasingly evident that there are definite correlations that can be made to oil field practice. Many of the techniques and generalizations on corrosive mechanisms made in condensate corrosion studies can be applied to oil field corrosion studies. It is the objective of this paper to generalize the facts known about gas condensate corrosion and integrate them with the work thus far done in oil well corrosion in order to present a discussion of corrosion which is applicable to both oil and gas wells. Thus, the corrosive agents, their actions, and methods that have been used to predict corrosive behavior will be discussed.

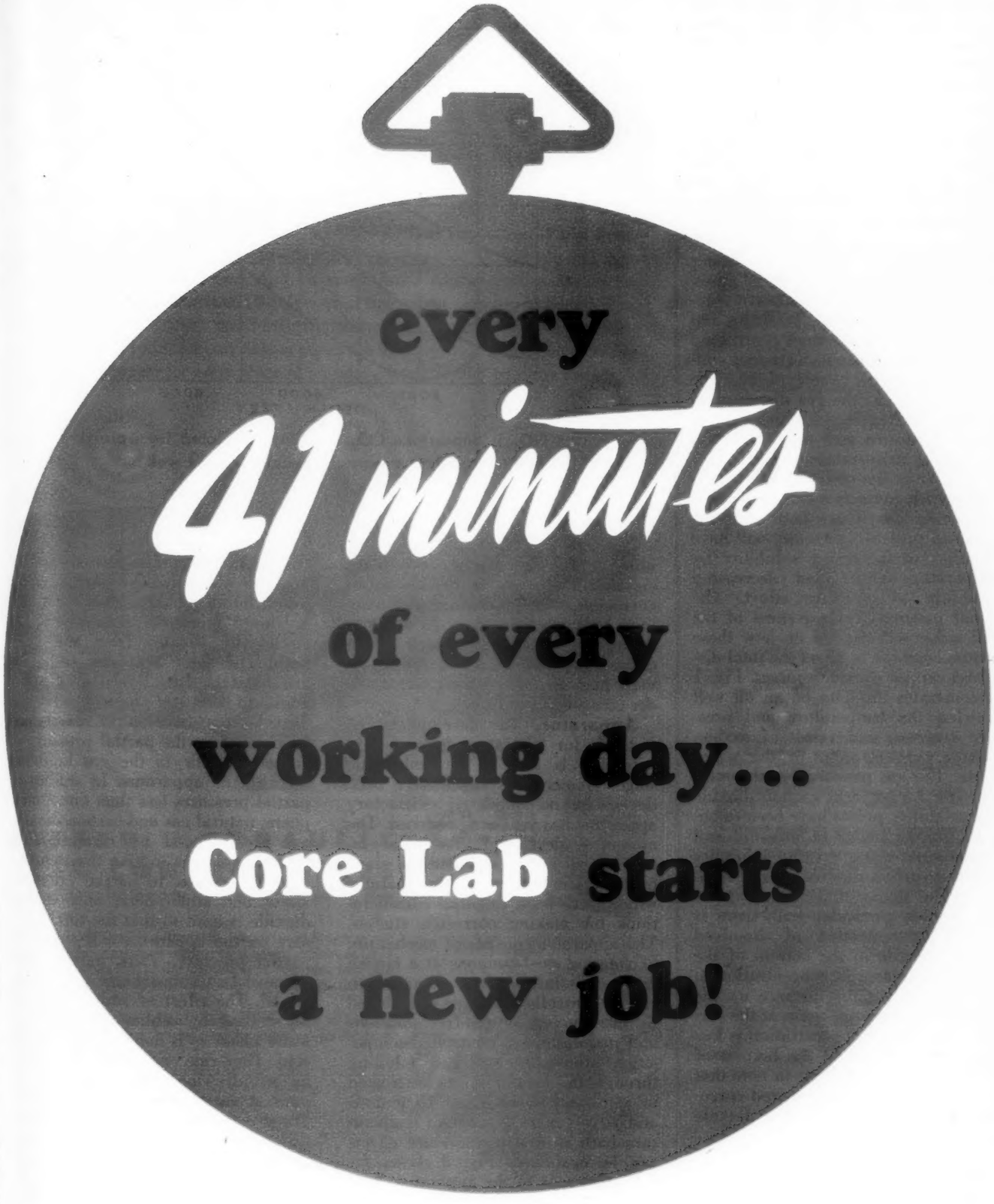
The Corrosive Medium—Water

In either oil or gas wells, the first prerequisite for corrosive action is the presence of liquid water. Corrosion takes place in the water phase and consequently a full knowledge of the nature of this phase is necessary if we are to understand or predict the course of corrosion. One of the major differences between oil and gas well corrosion is the behavior of the water phase. In condensate wells, the liquid water increases from formation to surface and there is good evidence that the liquid water is swept up the surface of the pipe in intimate contact with the steel. The corrosive water produced in a condensate well nearly comes to equilibrium reacting with the steel by the time it reaches the surface. In the case of an oil well, the water production is the same from the formation to the surface and the possibility of selective water flow along the pipe is improbable. The contact time with the water is reduced and surface effects, such as preferentially oil-wet areas and emulsion formation, make oil wells less corrosive than condensate wells of the same corrosive potential.

The Corrodents—Carbon Dioxide, Hydrogen Sulfide, and Lower Fatty Acids

The primary cause of internal corrosion is due to the acidity of the water phase. This is true in gas condensate and sweet oil production and, though no fundamental work has proved the point, there is good field evidence that this is true in sour crude corrosion. The mechanism by which an acid reacts with a metal describes the corrosion process in its simplest terms. Numerous attempts to correlate corrosion and various types of galvanic action and measurements of current flow have been unsuccessful in explaining the observed phenomena. On the other hand, the evidence accumulated in correlating corrosion and acidity has given a much more satisfactory explanation of the observed phenomena. In the simplest terms, it is believed that the internal corrosion of oil wells is the result of the hydrogen ion concentration in the water. The tendency to corrode is measured by the number of hydrogen ions. The rate is measured by the number contacting steel per unit of time. The hydrogen ions are supplied by the lower fatty acids, carbonic acids, and hydrogen sulfide. These are the corrosive agents. There is considerable variation on how the hydrogen ions are supplied to the solution by these corrodents, as they exist alone or in mixtures, and how the pure or mixed corrodents form corrosion products that alter the manner in which the steel is attacked. A more detailed discussion of the action of the fatty acids and carbonic acid will be made later. The data on hydrogen sulfide are not yet available but are mentioned here because it is believed that correlation does exist in the sour crude systems. The problem becomes

†Presented at the Spring Meeting, Pacific Coast District, Division of Production, American Petroleum Institute, Los Angeles, California, May 10 and 11, 1951.



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one of recognizing that the acids exist in the water, estimating their concentration, and the probable course the corrosion will take. Some information is available on the types of corrosion that can be expected for carbon dioxide and acetic acid in their mixtures and will be discussed later in detail.

Two of the corrodents, carbon dioxide and hydrogen sulfide, are gases at surface conditions. The gas phase represents a source from which corrodent can be continually supplied. The quantity of acids in the water depends on the solubility of the gases. Where sufficient or comparatively unlimited gas is available, pressures and temperatures are the chief controlling factors of the gaseous corrodent concentration in the water phase. The concentration of the gas dissolved in a liquid increases with the rise in partial pressure and decreases with increasing temperature. Thus, water coming from the reservoir to the surface, which contacts a carbon dioxide containing gas where both temperature and pressure decrease, will have an effect of increasing solubility by temperature effect and decreasing solubility by pressure effort. The actual potential corrosiveness of the well water will depend on how these factors combine to affect the total dissolved carbon dioxide content. Fig. 1 demonstrates the data on an oil well showing the temperature and pressure traverse and resultant carbon dioxide concentration in the water phase. The gas produced in this well contains 2.5 per cent carbon dioxide and solubility points have been calculated for the points of pressure and temperature, using existing solubility data for carbon dioxide in salt solutions. The shape of the curve shows that, in this particular well, there is a high concentration of dissolved carbon dioxide at the bottom of the hole. It decreases in concentration at about two-thirds the distance up the tubing and increases again at the surface. The surface concentration is less than concentration at the bottom of the hole. It is interesting to note that in this well it has been proved corrosion rates follow this carbon dioxide concentration curve.

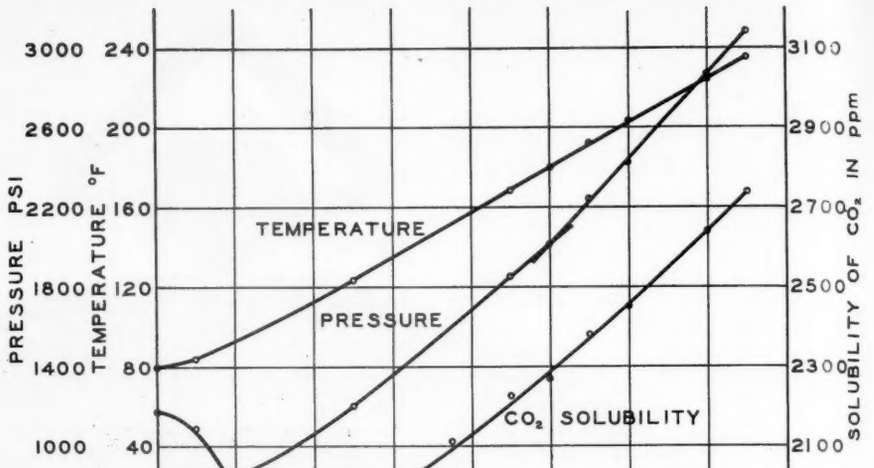

FIG. 1. Subsurface CO_2 solubility calculated from pressure and temperature surveys of a corrosive oil well.

The Effects of the Corrodents

Although the corrosion is due to hydrogen ion concentration, regardless of source, the path and various forms it exhibits are dependent on the anion providing the hydrogen ion and the nature of the other ions in the water. Thus, fatty acid corrosion, carbonic acid corrosion, and hydrogen sulfide attack, show widely different types. The mixtures of these corrodents with each other and the various anions from dissolved salts and soluble organic compounds can make significant changes in the course of corrosion. No producing well contains only one corrodent. In order to determine the effects of each of the corrodents and their mixtures, we must first investigate their action under controlled conditions.

Apparatus. The development of methods for laboratory tests of field corrosion is still in the embryonic stage. Numerous systems have been devised but no completely satisfactory apparatus has yet been produced. The apparatus developed in our laboratory is still in the experimental stage but contains many of the features which have been essential considerations for making corrosion studies. The apparatus consists of mechanism of rotating steel coupons at a known rate in a solution whose composition can be controlled. Oxygen is excluded by introducing oxygen-free solutions and maintaining a controlled-composition atmosphere of gas bubbling through the liquid. It is constructed to withstand pressures of 15 pounds and is placed in a constant temperature bath so that temperature effects can be evaluated. Fig. 2 shows the operating part of the apparatus. This unit is clamped to a heavy-walled pyrex jar to give a pressure seal and closed system as is required.

The coupons used are standard one-by-eight inch coupons used in the field evaluation studies and are inserted and removed through the pressure-lock system so that no oxygen can enter the main apparatus during this operation. Piping gases and solutions in and out of the apparatus is handled by connections through the plastic top. pH measurements are made by withdrawing a portion of the liquid into a separate chamber which is closed from the atmosphere but electrically isolated from the main bath. The fatty acid concentrations are maintained by introducing acetic acid into the water phase. The carbon dioxide concentration is maintained by controlling the partial pressure of carbon dioxide in the gas bubbling through the apparatus. In studies of partial pressures less than one atmosphere, natural gas and carbon dioxide are proportioned by rotameters in relative volumes to give the required partial pressure. In partial pressures above one atmosphere, only carbon dioxide is used so that the total pressure on the apparatus will equal the partial pressure. Thus, partial pressures of two atmospheres can be obtained. The effect of added salts can be studied by adding them in the water phase as is done with the acetic acid. Time-rate curves can be plotted by withdrawing and weighing coupons at various lengths of exposure. The surfaces are examined microscopically for pit attack and corrosion products can be identified by various analytical techniques. Corrosion by acetic acid, carbonic acid, and mixtures have been studied thus far in this apparatus; it seems to be a basically sound design. The curves to be discussed were developed using this apparatus.

Fatty Acid Corrosion (Acetic). The laboratory studies on the corrosive effects of water-soluble fatty acids are generally done using acetic acid. The justification for this has been that Lochte[1] and co-workers have found

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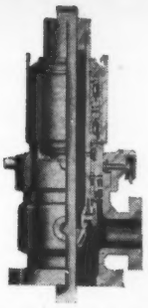

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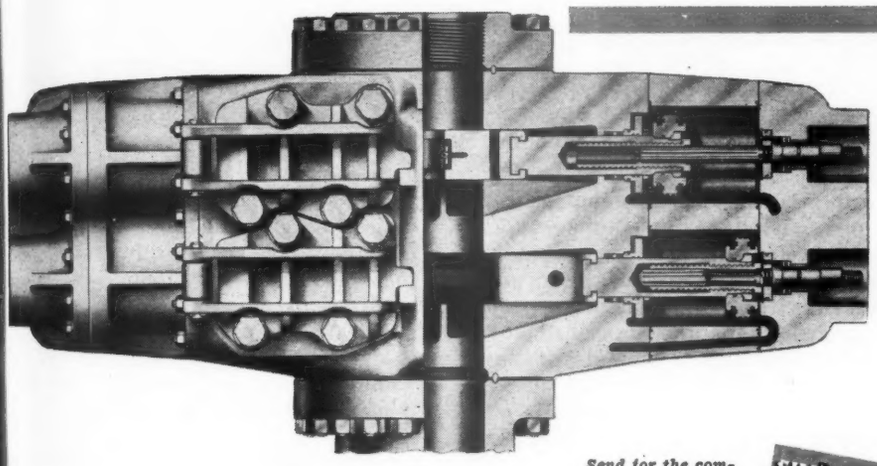

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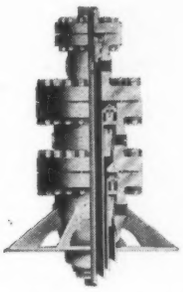

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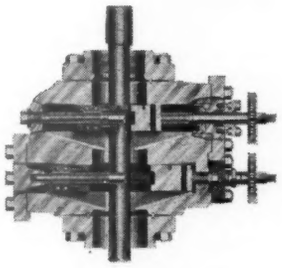

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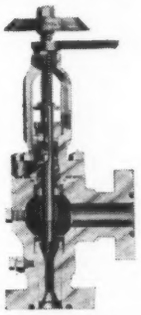

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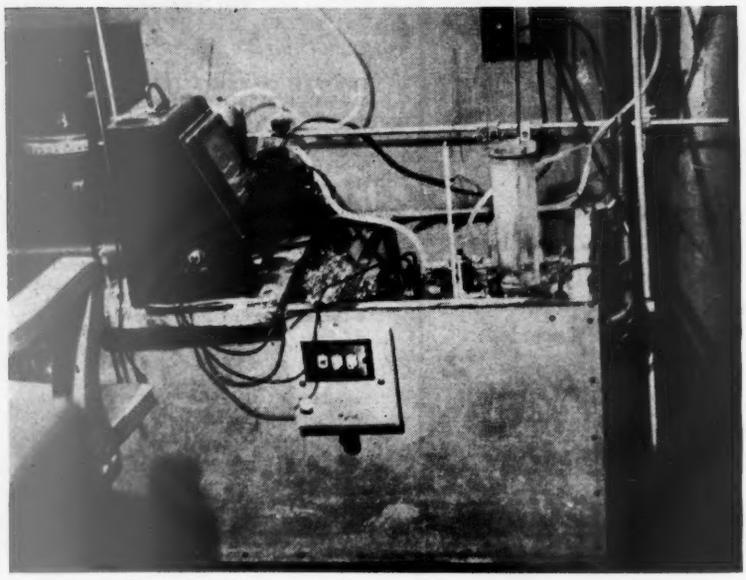
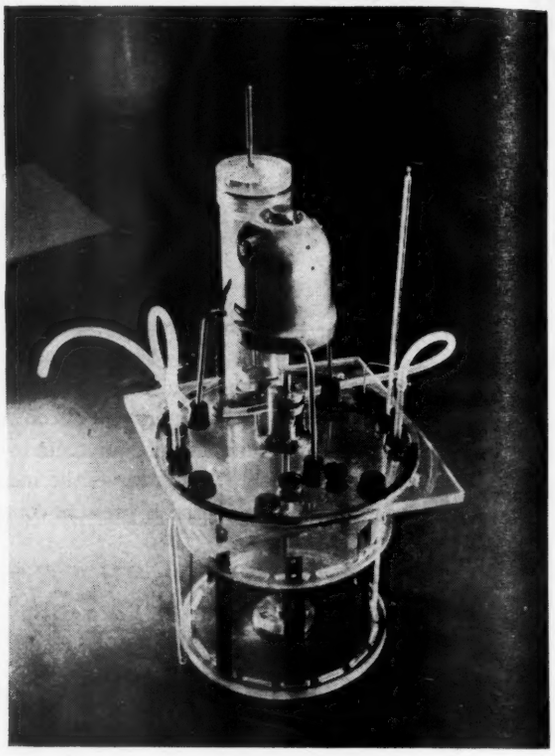
FIG. 2. Apparatus for development of laboratory tests of field corrosion. This is still in experimental stage.





that the greatest proportion of these acids in the water phase was acetic acid. The hydrogen ion activity of all the fatty acids is not too variant from that of acetic acid. Menaul[2] and Griffin and Greco[3] describe the corrosion in condensate systems caused by the fatty acids and, for a time, they were believed to be the principal causative agents in corrosive condensate wells. The laboratory and field studies demonstrate otherwise and their presence is now believed to be a contributing rather than a principal source of corrosion.

A series of experiments following the pH decline with time exposure[4] under controlled anaerobic conditions demonstrated that acetic acid will react with steel, forming ferrous acetate at a rate controlled by the temperatures of the solution and the velocity or volume of solution moved past the surface. The increase in temperature increased corrosion rates in amounts expected from chemical reaction rates. These results were taken as an indication that acetic acid corrodes steel by the solution of the metal or the surface products to form soluble ferrous acetate. Temperature affects the rate at which this reaction takes place in the same manner as it would any chemical reaction. Corrosion-rate curves exposing a series of coupons have shown that insoluble corrosion products are built up which generally reduce the rate. The composition of this corrosion product has not yet been determined.

Hackerman and Glenn[5] reported rate curves that followed no general pattern with concentration, using an apparatus that sprayed the coupons with acetic acid solution in anaerobic atmospheres approximating condensate well service. Corrosion rates, using the apparatus described above have been determined and are shown in Fig. 3. These curves show that the rate decreases in time, which is indicative of a semi-protective film being established. The corrosion rate does not drop to a negligible amount, however, and the metal continues to lose weight. It is important to note that in no case in any of the coupons was a pit attack found. Temperature is found to change the slopes of the curves but not their general shape. Concentration has no effect on the shape of the curves in this apparatus as it did in the results of Hackerman and Glenn. Both results, however, showed no pit attack and a decrease in rate with time when a semi-protective film was established.

Carbon Dioxide Corrosion. The fact that the carbonic acid concentration is pressure and temperature dependent makes corrosion tests more difficult to interpret on a comparative pH basis with the acetic acid. The forms of the curves and progress of corrosion, however, can be shown by the usual rate-change curves. These show some very significant differences from the acetic acid curves. The carbonic acid available for corrosive action is not only that which exists in solution like the acetic acid but is the amount that will dissolve from the gas phase after the reaction of the part already dissolved has taken place.

The laboratory apparatus approximates the action in the wells in that carbon dioxide is continually fed to the system to maintain its saturation equilibrium at the test temperature and partial pressure. Our tests with the present apparatus do not cover a wide range of conditions but they do demonstrate the mechanism. In Fig. 3 a corrosion curve is shown for coupons which are exposed to one atmosphere at 130 F. This curve represents the corrosion pattern of a joint in the tubing near the bottom of the well. The shape of the curve shows that the corrosion rate continues at a fairly constant value. There is no formation of a semi-protective layer. The layers formed aid pit attack so that after a time pits can be seen on the coupons which deepen as the corrosion progresses. From previous work in other apparatus, it was found that the solutions saturated with ferrous bicarbonate at one atmosphere pressure, which would be the equivalent to the joints at the top of the tubing, show the same type of curves and pit attack although the rate (slope of the weight-loss curve) was less than for the unsaturated iron solutions.

A comparison of the carbon dioxide weight-loss curve and acetic acid curve illustrates the reason why carbon dioxide corrosion is considered a major corrosive agent in the field. The fact that the corrodent is continuously supplied, that the reaction is not self-stifling, and that pit attack is produced, supports this claim. The carbonic acid concentration where negligible corrosion takes place has

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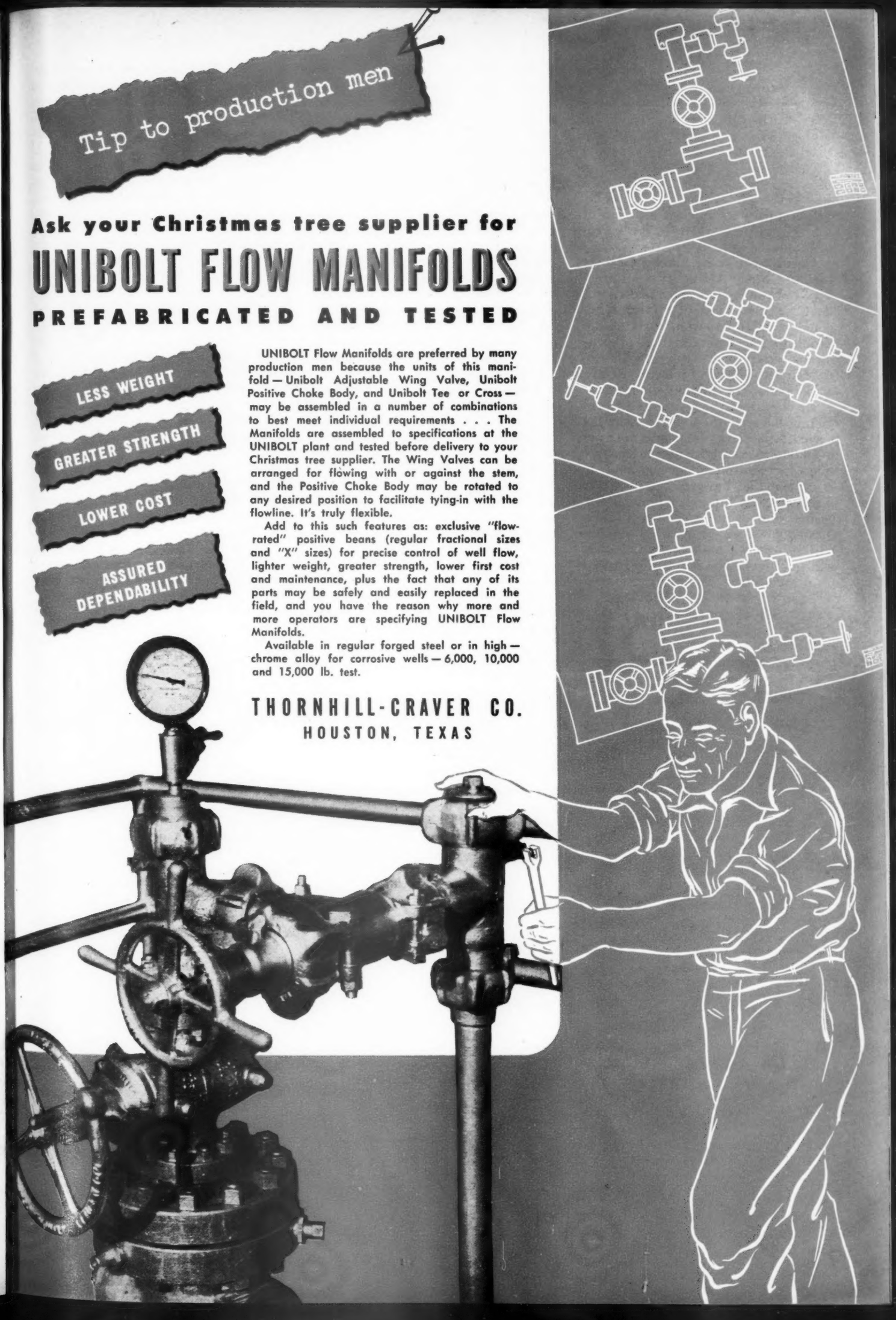


not been determined. It has been demonstrated by numerous experiments that a partial pressure of one atmosphere carbon dioxide or greater will give carbonic acid corrosion in most produced waters and that a partial pressure of .5 atmosphere carbon dioxide is in the neighborhood of a less severely corrosive range. This value is used as a rough estimate of the acid content where severe corrosion may be anticipated.

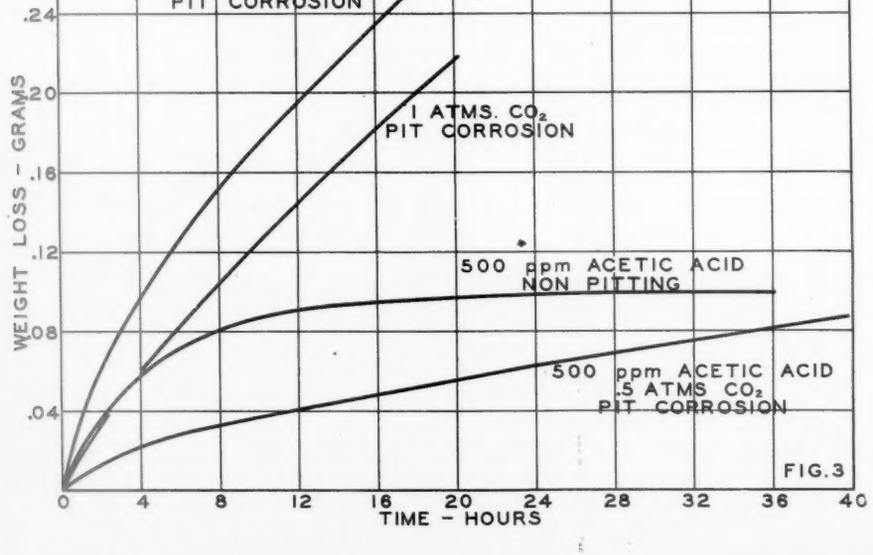
Combination of Carbon Dioxide and Fatty Acid. In actual practice, few wells have only one corrodent, so the study of mixtures becomes a most important part of the problem. The determination of conditions under which a well will corrode in accordance with the pure fatty acid or the pure carbon dioxide curve is an important consideration in predicting the type of corrosion to be expected. Sufficient data are not yet available to clearly define the conditions for controlling mechanisms. It is evident that the presence of acetic acid decreases the lower limit of the carbon dioxide effect so that a lower partial pressure of carbon dioxide will still give a high continuing rate and pit attack. The effect of mixtures of .5 atmosphere carbon dioxide and 500 parts per million acetic acid is also shown in Fig. 3. The addition of fatty acids to a system containing sufficient carbon dioxide to be corrosive increases the rate and severity of this attack. Data from the field on wells which contain low partial pressures of carbon dioxide (.1 atmosphere or less) and have organic acids in the water have been shown to develop typical acetic acid corrosion rate curves. The salt effects which will be discussed later may have a large enough effect in these wells to make the determination of such a limit of little utility in actual predictions.

The Effects of Retardants. Although the acids present in the water phase act as the aggressive agents, there exist compounds in the well systems that may retard the corrosion rate to such an extent that the well is considered non-corrosive. Such an occurrence is not uncommon and the fact that these situations do exist has caused some difficulty in identifying and evaluating the causative corrosive agents. The retarding agents fall into two general groups, the organic polar molecules and inorganic or buffering salts.

Polar Groups. Some of the early rate curves run in condensate wells showed that, with essentially the same potentially corrosive atmosphere, no corrosion took place.[6,7] After considerable study this difference was attributed to the presence of polar compounds in the fluids of the non-corrosive well. These compounds were not found in the fluids of the corrosive well. Rogers[8] demonstrated that addition of polar organic compounds such as turkey red oil and naphthenic acids to the well fluids changed the wettability of the steel and reduced the corrosiveness of a given system. He later demonstrated[9] that in oil wells certain crudes displace water from the steel surface and the addition of small amounts of organic compounds formed a completely oil-wet surface, thereby reducing corrosion rates in the well. Lochte[10] has found the presence of numerous oxygenated, high-molecular weight compounds in the condensed hydrocarbon phase of condensate wells. Their presence is also known in crudes, particularly those from California, West Texas, Wyoming and Kansas. There is little published information on the effect of various additives in the oils in a laboratory test apparatus such as has been used and discussed in this paper. These compounds, however, are similar in action to the organic inhibitors used in corrosion mitigation and are often termed "natural inhibitors." The subject of "natural inhibition" has not been investigated in any systematic manner and needs further proof in order to establish how widespread this effect may be. Regardless of the exact chemical compounds, the effect has been noted in the field in any number of cases and is easily detected by the coupon method.

Buffer Salts. Another group of compounds that can be classed as retardants is the dissolved salts that limit the hydrogen ion concentration. The produced waters containing these salts are then less acid than the partial pressure of carbon dioxide and temperature would indicate; thereby, the corrosion rate may be appreciably diminished. This buffer salt effect usually is not great enough to entirely eliminate the corrosion but may alter its severity and course. No data are available on the effects of natural-occurring buffer salts on the rate-change curve. However, this buffering action is the basis for the use of neutralizing agents such as sodium carbonate, bicarbonate, magnesium metal, and its salts as mitigation methods.[11,12]

FIG. 3. Typical corrosion curves for CO_2, fatty acid, and CO_2 and fatty acid solutions.



Prediction Methods

Having assembled the factors that influence internal corrosion, we now must be able to apply them to a particular well system if they are to be useful in our prediction work. In common with all prediction methods, the better the data and the better the evaluation of all influencing factors, the more likely the prediction will be fulfilled by performance. A weighed decision, balancing the worth of the increased accuracy of prediction against the cost of obtaining it, always confronts the corrosion engineer. Consequently, numerous evaluation schemes are used which yield varying approximations of true performance. These various short methods must be judged in the light of basic theory and principles if they are to be useful; otherwise, the interpretations of corrosive behavior are confusing and misguiding.

Inspection. Direct observation of a corroded piece of metal is more fact than prediction; however, such corrosion cases are usually warnings of the

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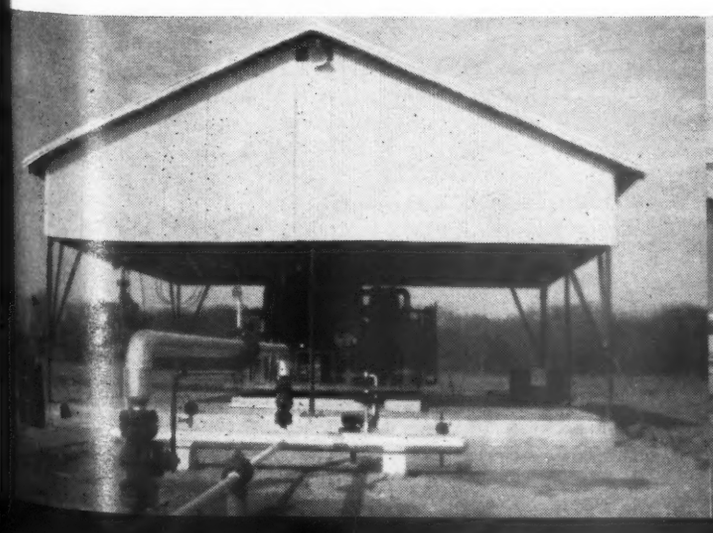

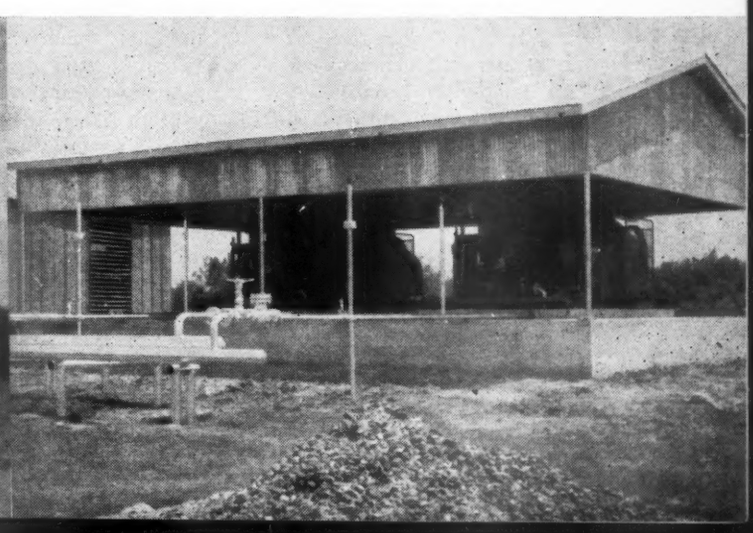

possibly more serious corrosion and such cases should serve as an order to investigate the potential corrosiveness of a well. In like manner, caliper surveys, such as are conducted by Otis, serve as a check on the severity of corrosion in tubing and casing; periodic checks indicate the rate and course the corrosion is taking. The discussion of corrosion logs supplied by the company includes the evidence of pit corrosion and general corrosion and, if the corrosion is localized at one depth or extends through the entire system, the caliper survey also serves as a check on other prediction methods rather than operating as a primary method itself. The caliper survey, combined with other prediction methods, is very useful.

Methods Based on Acidity of Water. As we explain the corrosion mechanism as an acid attack and the field data give evidence that this mechanism is correct, we are able to predict potential corrosiveness by measuring or estimating the pH in the water phase under well conditions. This can be done by analytical means and knowledge of the physical conditions. Eilerts[12] gives pH relationships for concentrations of carbon dioxide and the fatty acids in the concentrations as they occur in wells. Other values have been reported to the NGAA corrosion projects committee and are in the process of being released for general publication.[13] The usual procedure is to determine the carbon dioxide content of the gas at atmospheric pressure. From the total pressure, the partial pressure of carbon dioxide is determined. Then the effect of temperature at that partial pressure is estimated and the approximate pH value is determined. The fatty acid content is run on a sample of the water by titrimetric procedures outlined in the NGAA Corrosion Projects Committee's Tentative Standard Methods. The acidity developed from this source is estimated on the basis of the estimated acetic or propionic acid concentration found by analysis. Corrosion has been found to take place at pH values of 5.5 or less. The probable course of corrosion expected will depend on the anions present and was outlined briefly in the first part of the paper.

After a year of intensive field study and correlation work sponsored by the NGAA corrosion research projects committee, it was concluded that the following general rules were applicable to condensate well corrosion:[14]

1. Severe pit-type corrosion is to be anticipated in wells producing water contacted by a gas containing carbon dioxide at a partial pressure of one atmosphere or greater (well water pH 4.0-4.5).
2. Moderate or general corrosion is to be anticipated in wells in which the water contains the lower fatty acids and in which the gas phase has a low partial pressure of carbon dioxide (.2 atmosphere or less).
3. No corrosion is to be anticipated in wells containing no fatty acid in the water and the carbon dioxide partial pressure is less than .2 atmosphere.
4. The lower fatty acids increase the severity of the corrosion described in Case No. 1 so that a combined carbonic acid and fatty acid corrosion gives rise to a very severe pit attack.

These rules, first proposed in 1947, have been shown to be good first approximations in corrosion predictions and as such continue to be useful. The intermediate corrosion ranges and determinations of conditions for the differences in type attacks are not well defined nor is the limit of the corrosive acid range well determined. The approximations just made, if generally applied and used, would greatly improve the anticipation of corrosion.

Systems have been devised for measuring pH values under well-head conditions[15,16] that obtain estimates of the effect of dissolved salts and give proofs of the actual acidity in the produced water under well conditions. The data developed by these methods were useful in adding proof to the theory but are usually too lengthy to be used as prediction methods. The system used by Carlson[16] of placing the produced water sample under a pressure of carbon dioxide, which is equal to the partial pressure in the well, is useful in estimating actual pH values. His method gives an evaluation of the possible buffer behavior of the dissolved salts and shows good correlation with observed corrosion in the field and pH at field well-head conditions.

Methods Based on Iron Loss. Predictions based on the amount of metal lost per-unit-time are standard corrosion procedures. Both the indirect method, using iron contents of the water, and the direct method, using coupon exposures, are widely used and misused. Both methods are valuable tools but the results can be easily misinterpreted.

Iron Determinations in Water. The use of the iron content in produced waters for corrosion criteria assumes that the iron in solution comes from the corrosion of the steel. Useful as this method may be, it is the one method most subject to variation and can be applied only in a limited manner. In corrosive condensate wells, most of the water comes from the condensed vapor. The total amount is small and good contact is maintained. The water produced by them will have high iron values in terms of concentration. Thus, 100 to 200 parts per million iron is common in such cases. In corrosive oil wells where the total water volumes are much greater, the iron contents may be much lower, so that 25 parts per million iron content in a water may be indicative of a corrosive well. Trying to apply a general rule to both oil and gas wells and taking into account the total water produced, a system of evaluating corrosion by calculating iron as total pounds of iron lost per day has been suggested. This eliminates some of the discrepancy between high and low water producers. The corrosive limit values, however, are not the same for both condensate and oil wells. Very little data have been accumulated to ascertain if this method will be useful for prediction. One of the difficulties with any iron content method lies in the fact that the iron may come from the formation and not from corrosion. Results of a recent test clearly demonstrated that 130 parts per million iron, or equivalent 90 lb per day removal indicated loss, was coming from the formation. Practically no corrosion was taking place in the well.

The principal use of iron determinations in water, therefore, is a first check of possible corrosion. When the severity of the corrosion is established by other methods, the iron values are useful in following mitigation treatments. The method fails to give an indication of the type of corrosion. If insoluble iron products are formed, the method becomes unreliable or of no use. For instance, in hydrogen sulfide systems, the soluble iron reprecipitates as iron sulfide. No iron is found in solution even in quite corrosive waters. If the iron is from the formation, the corrosion estimates are in error.

Coupon Methods. As with iron values, the coupon method is one of the most commonly used corrosion evaluation methods. The most common method in oil field practice is to insert a tared steel coupon, usually 1020 steel, into the flow line for a known period, usually two weeks, and weigh again after descaling. The weight loss calculated to an average penetration value and reported as thousandths of an inch penetration per year (MPY) is indicative of the corrosion taking place. The surface of the coupon is examined microscopically for evidence of pit attack or evidence of protective surface film formation.

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on coupon testing in condensate wells which proved that the results obtained are indicative of the rates found in the well. Experiments performed at the University of Texas[6,7,17] determined rate curves by exposing multiple coupon sets in numbers of condensate wells. These rate curves gave results of typical curves obtained in the laboratory exposure tests and were discussed in a previous section. It was shown that very corrosive wells gave weight-loss curves like the typical carbon dioxide and carbon dioxide-acetic acid curves. The moderately corrosive wells gave curves like the typical acetic acid exposures and the non-corrosive wells showed a very low penetration rate and evidence of a protective film on the surface of the coupons. This type of coupon testing undoubtedly gives the best basis of estimated performance. It is too expensive, however, for anything but exceptionally difficult cases. Single-coupon exposures can be compared with known types and the probable corrosion behavior predicted. In the extensive tests carried out in condensate wells,[14] single well-head coupon exposures, which had been left in the well until a steady state had been established, gave some average penetration rates that indicated severe and less severe corrosive types. This survey showed the following results:

1. The very corrosive wells, which were the ones containing high partial pressures of carbon dioxide, gave surface coupon rates in the order of 10 mpy or more, along with evidence of pit attack.
2. The moderately corrosive wells, those with low partial pressures of carbon dioxide, and which contain fatty acids, gave surface coupon rates in the order of 5 mpy and no pit attacks.
3. The non-corrosive wells were those which showed evidence of natural inhibitors or buffer salts and no corrosion was present.

These general coupon tests seem to be applicable to oil well corrosion except that, because of the larger differences in pressure from top to bottom-hole conditions, surface coupons give low results. Thus, a severely corrosive well showed surface coupon corrosion rates of 7 mpy or less but was found to have subsurface rates up to 80 mpy. A special technique[18] has been devised for checking subsurface corrosion rates and has proved very useful in such cases.

Conclusion

The complexities of corrosion behavior are so great that it is difficult, if not impossible, to outline a single simple method for evaluating and predicting corrosion in all wells. The corrosion engineer must understand the possible corrosive mechanisms, then choose the methods that give adequate information at an economical cost. The acidity rules help in anticipating corrosion, the coupon systems help define its course, and the iron content methods are useful as indicators or comparison controls for mitigation methods. All these methods are useful, but the data yielded must be judged in light of the conditions of the particular well under test.

It is evident that the prediction methods are still in a state of development. Considerably more fundamental data must be accumulated before our present approximations can become more exact. It is believed that an extension of the laboratory studies such as were described in this paper could greatly extend our prediction accuracy and add to the usefulness of our present methods.

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Comments follow on Page B-98.

Drilling Emulsions in Exploratory Wells

If an entirely satisfactory method of identifying little amounts of oil is discovered, drilling emulsion in exploration wells will show a further increase, R. A. Henkes, Shell Caribbean Petroleum Company, Maracaibo reported recently. In his paper *Drilling Emulsion*, presented before the Third World Petroleum Congress at The Hague, Henkes reviewed the history of the development of emulsion muds from 1943, their preparation, principal properties, and present application.

The author reported that the use of drilling emulsions containing crude or refined oils have brought about remarkable increases of bit life and penetration rates, but he emphasized that he did not believe that by dispersion of just any type oil optimum increases in bit life and drilling speed could be obtained.

Drilling emulsions offer unique possibilities for the introduction of additives for specific purposes into a hole, as it carries both water and oil-soluble compounds, Henkes stated. Several references can be found in literature on corrosion and corrosion fatigue of drill pipe caused by the use of oil base mud or drilling emulsion.

Henkes also reported that in spite of the considerable advantages connected with the use of drilling emulsions, a common complaint against their use, particularly in exploration wells, is the difficulty of determining whether the oil that is found in cores is indigenous to the formation or emulsions. A refractometer is generally used by the Royal Dutch-Shell group of companies, thereby enabling the operator to determine on a very small sample if the oil from the core is identical to the oil contained in the emulsion or not. Neither the refractometer nor the fluoroscopic method is entirely satisfactory; the difference in fluorescence of the oil from a core and an emulsion is also used for this purpose.

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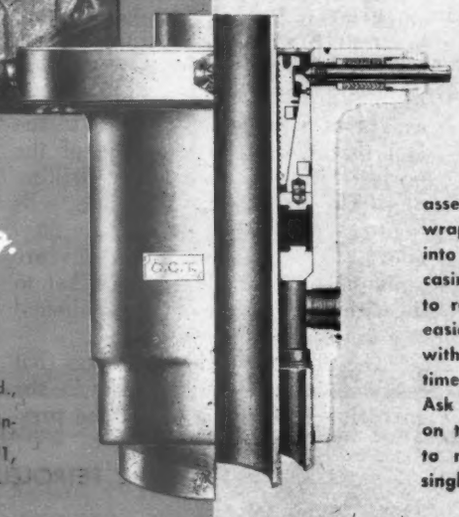

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COMMENTS ON PAPER: PREDICTION OF CORROSION IN OIL AND GAS WELLS

By A. J. Morrison,
Shell Oil Company,
Los Angeles, California

"The work of D. A. Shock and J. D. Sudbury is a great step forward in the formulation of the laws governing corrosion in oil wells. In this new field of study very little specific information regarding the mechanisms of this type of corrosion are known and no real progress will be made until they are finally evaluated. Any contribution such as the one under discussion is eagerly received.

"The following comments on the paper serve a double purpose: First, to offer an exception, in the case of pumping wells, to the general rule that "internal corrosion of oil wells is the result of hydrogen ion concentration in the water" and "the tendency to corrode is a measure of the number of hydrogen ions" and second, to offer an additional mechanism to those already mentioned, namely, bacterial attack.

Corrosion in Pumping Wells

"An exception to the general rule that corrosion depends primarily on the pH of the corrosive waters is found in the case of pumping wells. Although the general rule is still true it should always be mentioned that in any system under cyclic stress the effects of corrosion fatigue far outweigh the effects of overall corrosion due to hydrogen ion concentration.

"We offer the above exception to the general rule because our experience has shown that any corrosion alleviation program predicated on the pH rule alone will run into serious difficulties when applied to pumping wells. Our own experience is the painful example. Early in 1950 we sensed intuitively that corrosion was proportional to hydrogen ion concentration, so we devised a laboratory test apparatus similar to the one first described by J. N. Breston and proceeded to select inhibitors on the basis of the corrosivity of the various well waters. Remarkable curves were obtained and it appeared that the problem was solved with one preliminary step. We were soon disillusioned. The pumping well — the final arbiter — laid down its own inexorable laws and we discovered that cyclic stresses, galvanic potenial, and the pH value of the electrolite were creating phenomena violently at odds with our laboratory determinations. Laboratory examinations of sucker rod breaks indicated without exception that the failures were due to fatigue, which started with very tiny corrosion pits. In some cases rods were found to be in excellent condition otherwise, and that general corrosion attack was very light. But as pulling jobs are expensive we were confronted with the fact that one of the minor aspects of corrosion had become the most important economically. The ultimate correlation of the forces at work in pumping well corrosion are yet to be made and a true engineering solution to pumping well corrosion problems will await that day. But a word of caution regarding too general an acceptance of the hydrogen ion concentration theory for pumping wells seems to be wise at this point.

Bacterial Corrosion

"Any list of corrosive agencies would not be complete without some mention of the action of bacterial attack in oil wells. An article by Keith Doig of Shell Oil Company and Dr. A. Wachter of Shell Development Company, entitled "Bacterial Casing Corrosion in the Ventura Field" has been read and submitted to the NACE and it contains all of the pertinent data regarding Shell's recent findings in bacterial corrosion.

"Briefly it was discovered that where drilling fluids have a pH suitable for bacterial growth it is possible to introduce colonies of sulfate reducing anaerobic bacteria behind the well casings, which can result in serious corrosion. To date, 46 well casings have failed through this type of attack. In this particular type of corrosion the bacteria reduce sulfates. (a) to obtain oxygen for the oxidation of organic substances, and (b) for the oxidation of hydrogen for the production of energy, at the same time forming H_2S.

"Tests were made from asceptic cores taken between depths of 3000 to 4000 ft to determine if bacteria were present in situ. While the resulting cultures were not conclusive the weight of evidence still points to the fact that the primary source of the bacterial invasion was from drilling mud. The remedy for all future wells is to raise the pH of the drilling fluid above 10 because effective kills are made at such an alkalinity. What to do with wells presently contaminated is a question not yet solved.

"The above evidence indicates that bacteria are a potent factor in the corrosion field. Evidence of the presence and effectiveness of these organisms have subsequently been found in salt water disposal systems, field storage tanks, and in absorption plant cooling systems. Their recognition and evaluation are a part of any well rounded corrosion investigation."

By Oil and Gas Well Corrosion Committee,
Pacific Coast Branch TP-1A
National Association of Corrosion Engineers
Presented by E. O. Kartinen

"The authors have summarized the basic theories of corrosion as are known today. An understanding of the principles described form one of the tools that an engineer must have to enable him to properly study the problem of "Down the Hole Corrosion" in oil and gas wells.

"The other tool that an engineer needs deals with the physical or practical aspects of the problem of oil production. Such factors that must be considered along with the laboratory studies include items such as string stress distribution that includes stress ranges and reversal frequencies as applied to both rod and tubing strings. Another factor is that of abrasion resulting from metal to metal contact in a corrosive media, movement of fluid borne solids, and the errosive action of turbulent fluid flow.

"This paper once again calls the attention of the oil industry to the problem that is probably the largest single factor in subsurface operating costs.

"Laboratories are learning the basic principles related to corrosion. Field groups are finding progressively more effective means of applying those principles. An increasing awareness of the costs of corrosion has stimulated research efforts, and we may expect a rapid extension of our fundamental knowledge and a major progress in the development of the practical field techniques for predicting and controlling corrosion.

"The authors are to be complimented on the timeliness of this paper. The industry is indebted to them and such organizations as the American Petroleum Institute, the Natural Gasoline Association of America, and the National Association of Corrosion Engineers, who have been the pioneers in the study of basic corrosion theories, its predication and mitigation.

"The paper, although complete in itself, may be likened to a door, which, now opened will reveal entirely new concepts and techniques. The paper invites further study and experimentation that should provide the basis for additional reports on this vital subject." * * *

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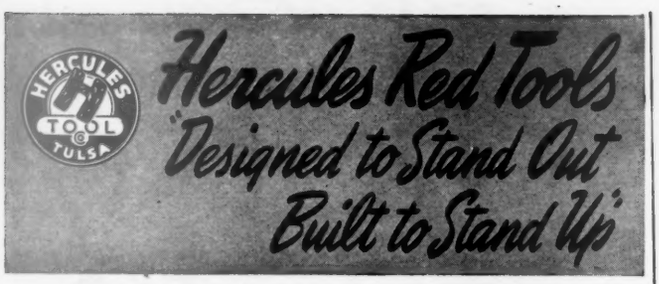

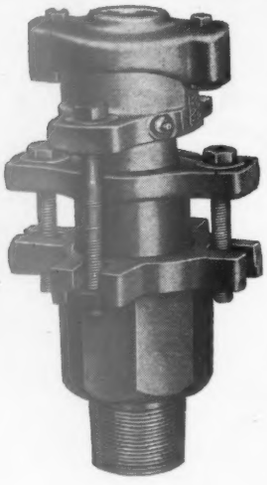

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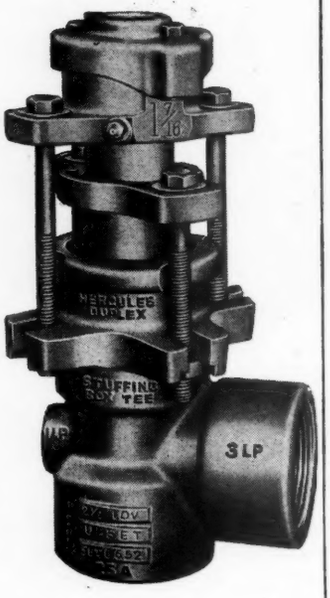

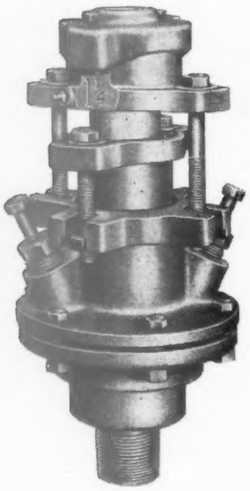

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Automatic Oil Well Drilling and Producing Is Foreseen

Forecasts that automatic drilling of oil wells will be perfected and automatic production of oil leases will be extended in the near future, were heard by attendants of the Gulf Oil Production Engineering Conference in Pittsburgh, Pennsylvania recently.

John H. Starbird, production engineer for Gulf at Paloma, California, and E. L. Petree, district superintendent of production, Houston division, reported on progress in the automatic field as highly promising.

Drilling Rig Control

Automatic controls, Starbird said, are being developed with the aim of permitting devices on drilling rigs to operate by themselves after proper adjustment by the driller, and to take care of variances in operation without further correction.

Such equipment will not replace the driller, he asserted, but will relieve him of the constant alertness required to operate the drill brake and give him more time to supervise rig maintenance.

The resulting mechanical elimination of human error will effect many advantages, he asserted.

By controlling the weight of the drill string with automatic precision, the hazard of "twist off" will be decreased. By permitting the bit to drill at maximum speed at all times, even while the driller is supervising the rig, the automatic equipment promises to reduce drilling time.

Automatic Weight Control

Automatic weight control, he said, is expected to decrease bit wear. The automatic equipment can also give directional accuracy, contributing to drilling straight holes.

Much development work has been done on such apparatus. A number of devices are in the experimental stage but others have recently been operated successfully. On the basis of this current experience, Starbird declared:

"I am sure that in the future the industry will realize a completely automatic rig that will be economically justified."

Taking up the application of automatic devices to producing oil leases, Petree said that beginning in 1948, a number of leases have been so equipped. As a result of these experiments, the devices used have reached the proved stage.

The equipment permits wells of the leases to be produced on a 24 hour a day basis, or to be turned on and shut off at intervals required to produce a specified output of oil per day.

When sufficient numbers of leases have been set up on an automatic basis, he predicted, the general production operation will be simplified, and, "in fact, will be set up on an assembly line basis."

Routine Well Checks

Pumpers will make routine checks of wells and tank batteries to ascertain if the wells are producing correctly. Producing equipment will be checked on schedule by technicians, who will perform the necessary servicing. Lease maintenance, such as cleaning and painting equipment and flow line repair, will be done on contract.

In East Texas, leases totaling 415 wells are already being automatically produced, he said, and tentative plans are to substantially extend the method.

Advantages that support this trend include, he stated, that every well is produced every day; wells can be staggered in their flow schedule providing a constant flow of gas to the gasoline plant; and finally greater overall economy of operation.

Not all types of leases, he cautioned however, are adaptable to automatic production.

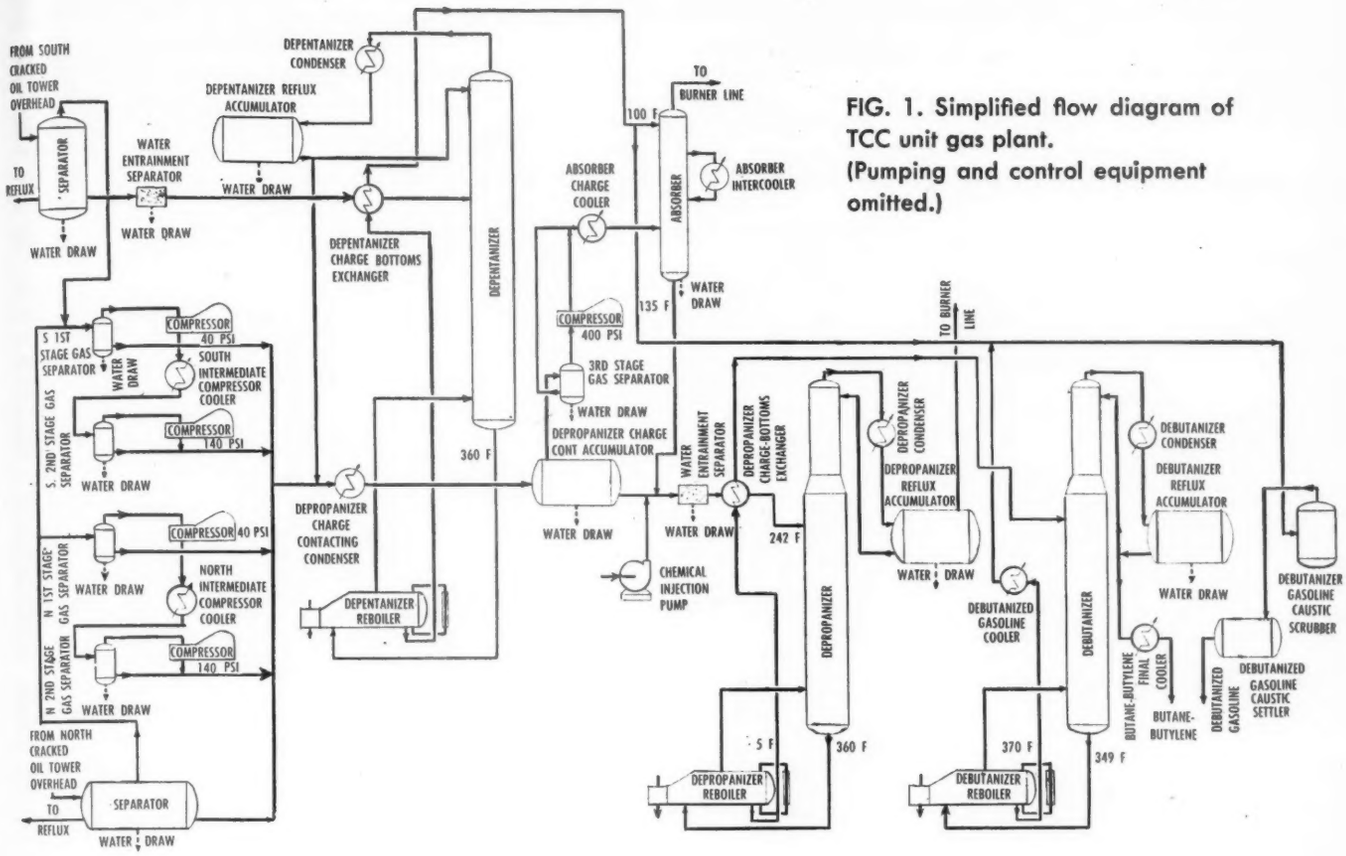


FIG. 1. Simplified flow diagram of TCC unit gas plant. (Pumping and control equipment omitted.)

Corrosion-Prevention in a TCC Gas Plant†

Measures consist of removal of water with coalescers at appropriate points

C. A. MURRAY* AND M. A. FURTH*

FEED to the gas plant at the Smiths Bluff refinery of Pure Oil Company, Nederland, Texas, consists of liquid gasoline and lighter vapors from the TCC units. It includes water from process steam and corrosive chemicals such as hydrogen sulfide, ammonia, and volatile organic acids, which result from the breakdown of parent compounds in the charge oil during the cracking reaction.

Description of Gas Plant

Fig. 1 is a simplified process flow sheet of the gas plant, including the temperatures, pressures, and steam flows at various points in the system.

This gas plant serves two TCC units; it is conventional, with a depropanizer, an absorber, a debutanizer, and a depentanizer as the fractionation towers. The gas plant has a compression system, which consists of three compression stages to 40 psi, 140 psi, and 400 psi, respectively. There are various water separators, heat exchangers, coolers, and reboilers—all of which have been subject to varying degrees of corrosion.

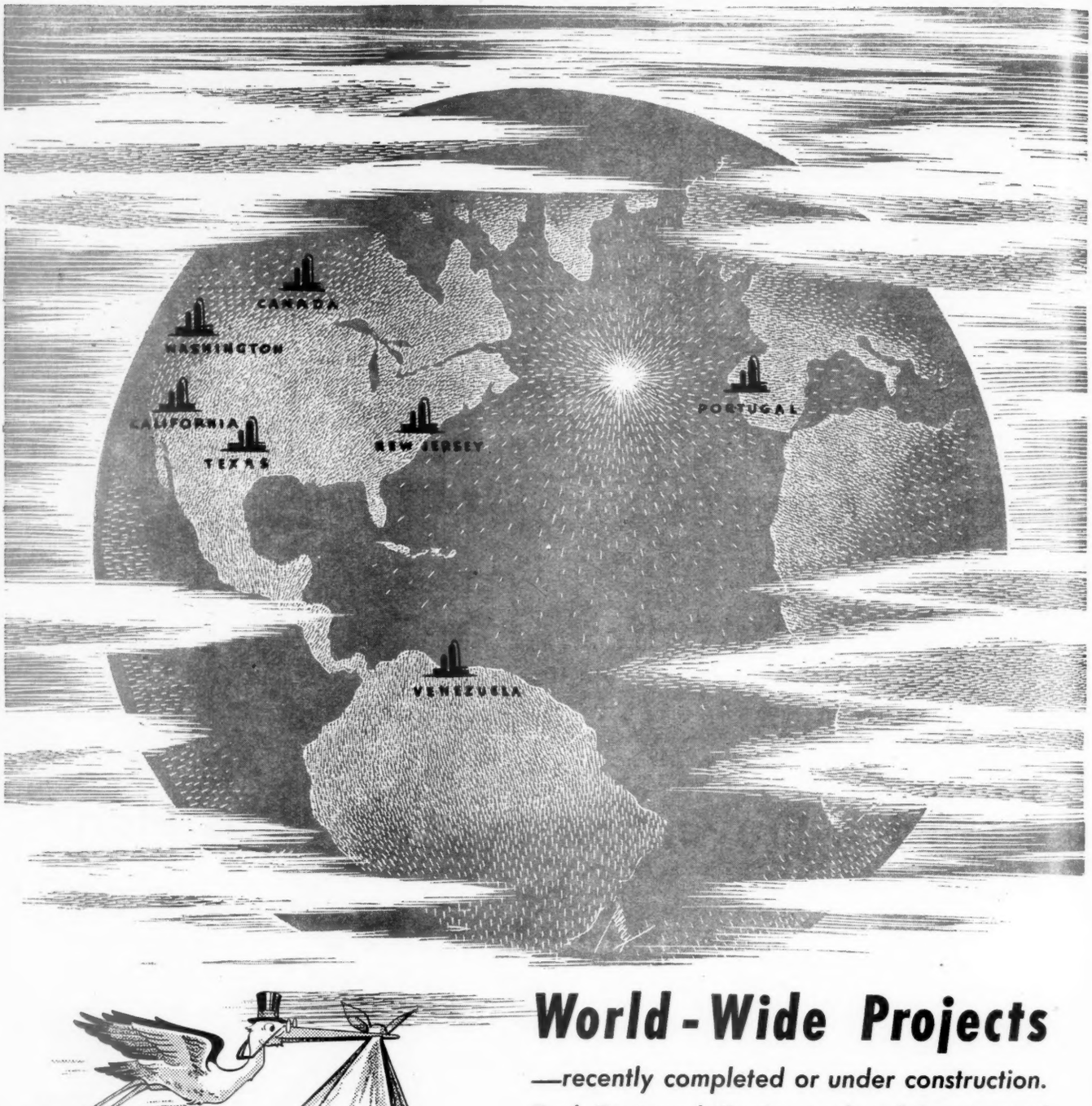
Replacement Time

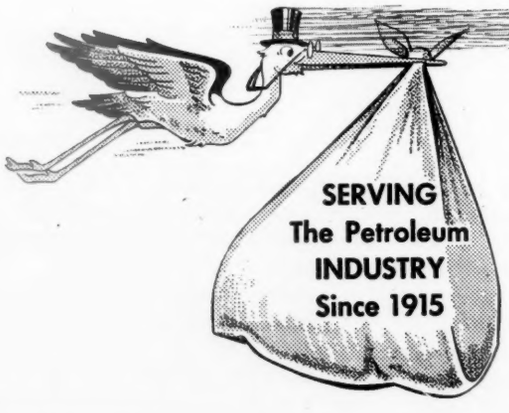
Corrosion in the shell-and-tube type heat-exchange equipment has been unusually severe. Even though major retubing was done during regular inspection shutdowns of the unit, there have been frequent unexpected failures that occurred during operating periods.

The depropanizer charge-bottoms exchanger tube bundle had to be retubed or replaced 5 times in 65 months. The shell was replaced once, and thin spots on the new shell were wash-welded during the same period of time. Admiralty tubes were substituted for steel at the time of the second retubing, with a slight improvement in life. The debutanizer reboiler, which had steel tubes, was retubed or replaced 6 times in 61 months. These failures, having taken place in relatively hot streams, suggested the presence of a corrosion reaction accelerated by heat.

†Presented to a corrosion session during the 16th Mid-Year Meeting of the American Petroleum Institute's Division of Refining, Tulsa, Oklahoma, May 1, 1951.

*The Pure Oil Company, Smiths Bluff Refinery, Nederland, Texas.





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Admiralty tubes were used in the depropanizer and debutanizer condensers. The depropanizer condenser required four retubings because of corrosion from the process side over five years' operation. The debutanizer condenser required retubing once after four years of service. This was also because of corrosion from the process side.

The original steel tubes of the absorber charge cooler were replaced with steel after 16½ months of service, and then with 70-30 copper-nickel after 18½ months of service. Corrosion on the process side of both metals was noticeable, but not to the same degree as that experienced at other places in the gas plant.

Corrosion Causes

In searching for a possible explanation for corrosion in the depropanizer overhead stream and in the absorber charge stream, it was found that quantities of water were associated with these streams. It was postulated that corrosive chemicals carried in water might be responsible in some degree for corrosion having taken place. The theory that water-soluble chemicals influenced corrosion was supported by a comparison of the depropanizer and the debutanizer condensers.

The depropanizer condenser bundle is pictured in Fig. 2. This bundle has a badly scaled-up and fouled appearance. The debutanizer condenser bundle is shown in Fig. 3. This bundle presents a relatively clean condition, and shows no significant corrosion to date. It is felt that the relative dirtiness and abundance of corrosion products in the depropanizer condenser, as compared to the debutanizer condenser, may be attributed to the relative quantities of water present in the streams.

The intermediate amount of corrosion and scale found present in the absorber charge cooler is felt to be the result of an intermediate quantity of water having passed through the cooler. Bundles in relatively hot streams experienced corrosion. Bundles in relatively cool streams with large amounts of water experienced corrosion. In relatively cool streams where water was absent, the corrosion experienced was negligible.

Corrosion Survey

It was determined, from qualitative analytical work, that the principal corrosives present were hydrogen sulfide, ammonia, and unidentified organic acids, in water solution. Accordingly, a complete gas-plant corrosion survey was made; and the concentrations, in per cent by weight of corrosives in water, plus water present in gallons per day, were estimated for the various streams of the gas plant. Results of this survey are as follows:

1. Water entering the gas plant from the cracked-oil tower overhead separators:
   - A. Water vapor with gas feed to compression system: 3850 gal per day, as liquid.
     Water condensate at compression plant from north first-stage separator: pH, 8.5; ammonia, 0.07 per cent; hydrogen sulfide, 0.12 per cent.
   - B. Entrained water with liquid hydrocarbon from north cracked-oil tower overhead separator: 850 gal per day; pH, 8.5; ammonia, 0.035 per cent; hydrogen sulfide, 0.054 per cent.
   - C. Entrained water with hydrocarbon from south cracked-oil tower overhead separator; 300 gal per day; pH, 8.0; ammonia, 0.042 per cent; hydrogen sulfide, 0.081 per cent.
     Total: 5000 gal per day.
2. Distribution of water through the depentanizer:
   - A. Water charged to depentanizer: 300 gal per day; pH, 8.0; ammonia, 0.042 per cent; hydrogen sulfide, 0.081 per cent.
   - B. Water leaving depentanizer overhead (plus reboiler leak at time of survey): 719 gal per day; pH, 7.6; ammonia, 0.083 per cent; hydrogen sulfide, 0.18 per cent.
   - C. Water leaving depentanizer bottom: 104 gal per day; pH, 6.3; organic acids (as acetic acid), 0.006 per cent.
3. Distribution of water through the depropanizer:
   - A. Water charged to depropanizer: 2090 gal per day; pH, 8.5; ammonia, 0.30 per cent; hydrogen sulfide, 0.53 per cent.
   - B. Water leaving depropanizer overhead: 290 gal per day; pH, 7.7; ammonia, 0.85 per cent; hydrogen sulfide, 1.52 per cent.
   - C. Water leaving depropanizer bottom: 1800 gal per day; pH, 8.0; ammonia, 0.002 per cent; hydrogen sulfide, 0.004 per cent.
4. Distribution of water through debutanizer:
   - A. Water charged to debutanizer: 1800 gal per day; pH,

FIG. 2. Depropanizer overhead condenser bundle.

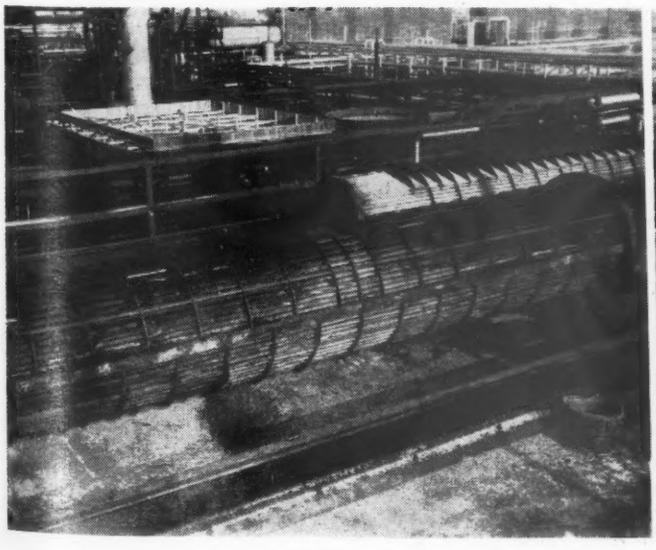
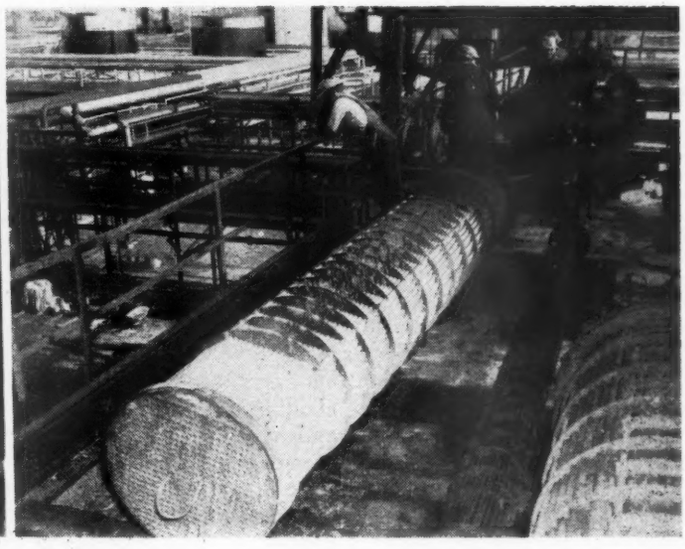


FIG. 3. Debutanizer overhead condenser bundle.



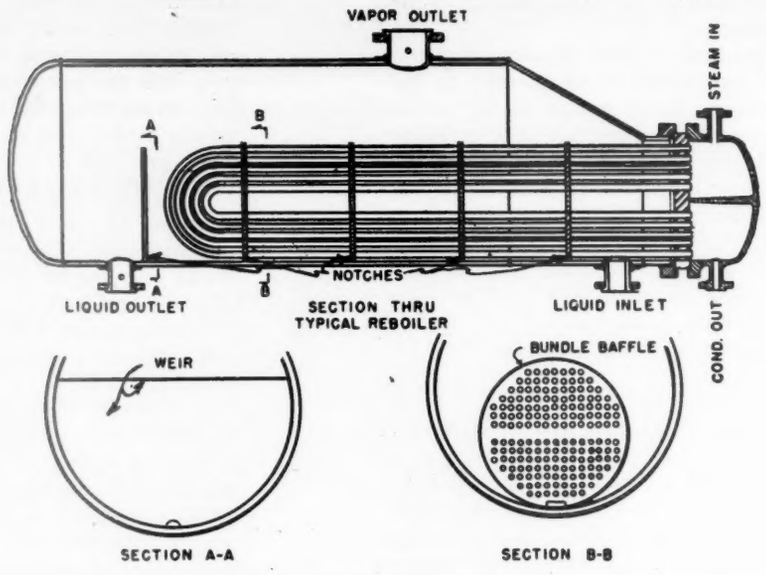


FIG. 4. Arrangement of sludge-drainage notches in weir and baffles in reboilers.

8.0; ammonia, 0.002 per cent; hydrogen sulfide, 0.004 per cent.

B. Water leaving debutanizer overhead: 90 gal per day; pH, 8.8; ammonia, 0.006 per cent; hydrogen sulfide, 0.004 per cent.

C. Water leaving debutanizer bottom: 1710 gal per day; pH, 5.5; organic acids (as acetic acid), 0.012 per cent.

5. Estimate of water passing through absorber:

A. Water leaving absorber: 320 gal per day; pH, 7.3; ammonia, 0.143 per cent; hydrogen sulfide, 0.336 per cent.

Chemical Corrosives

From the foregoing it can be seen that there were normally 5000 gal of water per day introduced to the gas plant. One source of water was vapor introduced with the gas from the cracked-oil tower overhead gas and water separators. A second source was entrained water carried along with gasoline from the bottom of each of the separators into the gas plant. It will also be noted that, at the time of the survey, there was a depentanizer reboiler leak, which introduced water into the depentanizer, from whence it progressed overhead, and on into the depropanizer charge. Water which had accumulated in the depropanizer charge accumulator was an alkaline solution containing ammonia and hydrogen sulfide. In bottom streams, however, such as the depentanizer or debutanizer reboiler, the water was slightly acidic. The water contained ammonium salts of organic acids, which had dissociated at reboiler temperatures to produce an acid solution which, in conjunction with corrosion products carried to the reboiler, produced very severe localized attack on reboiler tubes. It is very likely that the heated depropanizer charge stream and also the depropanizer reboiler stream similarly contained salts that gave acid conditions during actual operation.

Corrosion Products

In addition to corrosive chemicals carried by water in the streams, it was indicated that corrosion products, such as metallic sulfide sludges, were a factor in producing localized attack. The adverse corrosion influence of corrosion-product sludges was emphasized at the time of a debutanizer reboiler failure in January 1949. Inspection indicated considerable iron-sulfide sludge lodged at the bottom of the reboiler bundle and also packed around the bottom reboiler tubes. Surface losses of bottom tubes which had been in the sludge averaged 0.020 in. Surface losses of top tubes which were not in contact with the sludge averaged 0.002 in. The bottom tubes were severely pitted, whereas top tubes had a slight uniform attack. Tubes of this bundle had been in service but three months.

Preventive Measures

Inasmuch as the corrosion had been so closely connected with water, it was thought that the most practical measures for corrosion prevention should consist of water-removal steps wherever possible in the gas plant. It was recommended that water be removed at four different places:

1. 300 gal per day of water entered with gasoline from the bottom of the south cracked-oil tower overhead separator. It was recommended that this water be removed with a coalescing-type entrained-water separator.
2. 850 gal per day of water entered with gasoline from the bottom of the north cracked-oil tower overhead separator. It was recommended that more water-settling capacity be provided at this point. Separation of this stream should be more in line with the efficiency of the present south cracked-oil tower overhead separator.
3. A further source of water in the gas plant consisted of that which had resulted from condensation of water vapor, following the various compression stages, plus water from compressor drip gasoline which becomes entrained in depropanizer charge accumulator hydrocarbon liquid. Although water had been removed at the separators prior to compression and after the first-stage compression, no water was removed after the 140-psi or the 400-psi compression. It was suggested that a flood nipple be provided in the absorber bottom outlet, with provisions for a separate water draw from the bottom of this tower.
4. It was recommended that a coalescing-type entrained-water separator be provided at a point upstream of the depropanizer charge exchanger to remove the remaining free water.

It was anticipated that, after water had been eliminated as far as possible from the gas plant by the proposed measures, trace amounts of corrosives might still remain in small quantities of residual water. Chemical neutralization was then suggested in order to effect further corrosion reduction, if required. To accomplish this, it was thought that ammonium hydrosulfide dissolved in water might be decomposed or rendered inert. Bottom stream ammonia-organic-acid salts might be converted to salts less likely to dissociate with heat, such as sodium or amine salts. Provision for such chemical injection was therefore, recommended at a point prior to the depropanizer charge-bottoms exchanger.

It will be recalled that the debutanizer reboiler tube failure was connected with iron-sulfide sludge, which had lodged at the bottom of the re-

boiler bundle. Indications were that the sludge acted as a coalescing medium for water, or that it was cathodic to carbon steel and may have accelerated corrosion by galvanic effect. It is likely that both influences accelerated the corrosion. Of course, the source of the sludge was in part caused by corrosion of the tubes themselves; but the larger part of the sludge was the result of attack by hydrogen sulfide farther back in the system. Liquid in the system carried sludge particles over to the reboiler. Laboratory tests have also established the increased corrosion tendencies of such sludge under stimulated conditions.

To reduce this corrosion, pending the installation of entrainment separators where they had been recommended, the sludge factor was reduced by notching the bottoms of baffle plates of the tube bundle, and by enlarging the weep hole of the weir plate in the reboiler so as to encourage more thorough drainage of water and sludge to the bottom process outlet connection. A sketch of the drainage and drawoff arrangement is given in Fig 4.

This bundle was open for inspection three months later. Little sludge was found, and no further measurable metal loss had been experienced on the bottom row of tubes, viz., the same row that had failed after having been submerged in sludge and water in the previous three months.

The bundle was not open for inspection for another seven months, when again some sludge deposits were found in the middle tubes near the bottom of the bundle, and when the bottom tubes showed slight additional corrosion losses. Inasmuch as the bundle was already corroded at the time the weir notching was done, these losses, as well as overall additional losses, were sufficient to warrant the installation of a newly retubed bundle. Six months elapsed before the next inspection of the bundle. At this time the tubes were found to be pitted and corroded, with the area of deepest pitting in the top portion of the bundle. Although the tubes had not failed, earlier unsatisfactory experience prompted a conservative decision to avoid the possibility of an unexpected failure, and the bundle was retubed. These results indicate that the baffle notching and drainage of reboilers had served to avoid emergency gas-plant shutdowns resulting from failure of the bottom rows of tubes. However, corrosion—although at a reduced rate—was still taking place in the reboiler because water was passing through the bundle.

Water-Removal Measures

Three of the recommended measures for water removal subsequently were put into effect. The first was the installation of a flood nipple in the bottom of the absorber tower, with the establishment of regular manual water withdrawal every four hours. Water is regularly drawn from this point. It is believed that this procedure has accomplished its purpose by lessening the load on the entrainment separator placed farther down-stream in the system.

The second water-removal measure was the installation of a coalescing-type entrainment separator on the depentanizer-feed gasoline stream. This entrainment separator is simply a small vessel which contains excelsior as a coalescing agent and which has a small leg for the purpose of trapping the separated water. The trap has an automatic liquid-level control, which provides for disposal of separated water. A picture of the separator installation is given in Fig. 5.

This separator has been very successful in operation, and has required no particular servicing or attention to accomplish its job. Water removal in this system was for the purpose of providing corrosion protection for the depentanizer charge-bottoms exchanger, the depentanizer reflux condenser, and the depentanizer reboiler. This section of the gas plant has not been open to inspection since the installation of drying facilities, and it is not possible at this time to report results.

The third water-removal measure was the installation of a coalescing-type entrainment separator on the depropanizer charge stream, following its juncture with the absorber bottoms stream. At this point the stream is all in a liquid state, and the water present is susceptible to removal by coalescing means. Like the depentanizer charge entrainment separator, this separator also utilizes excelsior for a water-coalescing agent.

Although the water-removing capacity of this separator is larger than that for the depentanizer charge, its efficient operation depends to a large

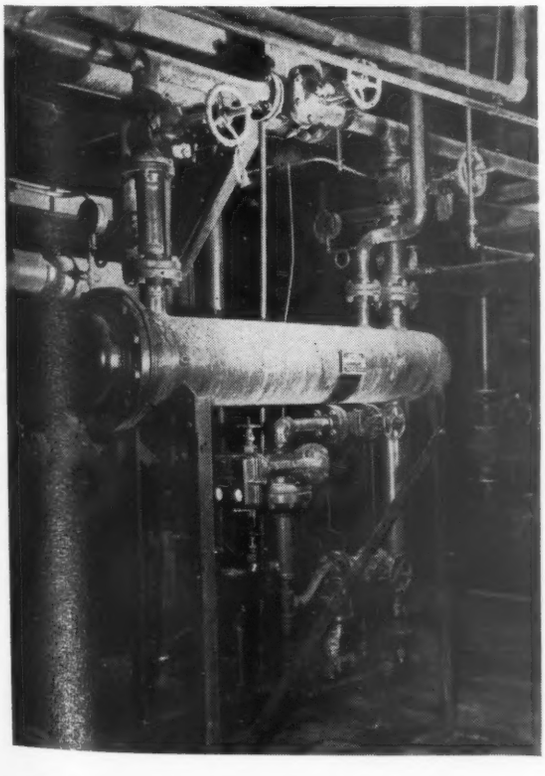
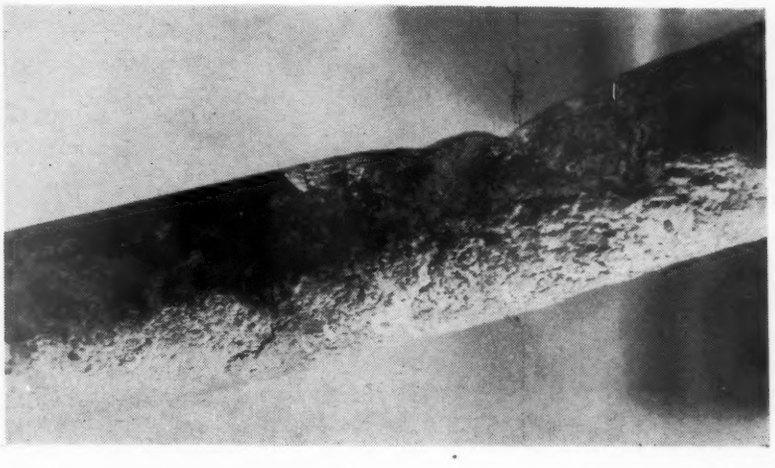


FIG. 5. Typical installation of coalescing-type water-entrainment separator.

FIG. 6. Corrosion on depropanizer charge—Bottoms heat exchanger.



extent on adequate manual removal of excessive water from the depropanizer charge accumulator. Excess water still continues intermittently to load the charge accumulator, and will do so until such time as the separator efficiency on the north cracked-oil tower overhead stream is increased. The construction and location of the charge accumulator is such that its use as a water separator is difficult and inefficient, and it follows that the manual water-drawing operation is an inefficient one.

This difficulty is especially significant because large amounts of water were allowed to pass into the depropanizer charge stream during an initial two-month period before water-drawing procedures at the depropanizer charge accumulator were emphasized. It is likely that intermittent introduction of water into the depropanizer charge has occurred even during the following period of operation.

The depropanizer-debutanizer section of the gas plant was open to inspection January 1951—7 months after water-removal measures. It is possible in this short period of time to describe results that are considered indications of successful corrosion prevention.

Definite improvement in corrosion experience was found in the depropanizer charge-bottoms exchanger. Each previous year this tube bundle had been so extensively corroded on the shell side that retubing was necessary. During the last inspection shutdown the corrosion was minor for the bundle as a whole, and was severe at only two places. A small amount of sludge had lodged between the tubes and baffle at the first baffle, and between the tubes and tube sheet at the floating tube sheet. The sludge and corrosion had been confined to these two places only on the bottom three rows of tubes. At the point of sludge contact with the tube, the tubes had corroded areas 1 in. to 2 in. long. The area of corrosion on one tube is indicated in Fig. 6. It is emphasized that, except for these two areas of sludge accumulation, at no place had the tubes lost significant amounts of metal. Previously all tubes of this bundle had shown excessive corrosion for a similar period of operation. It is believed that the corrosion in this exchanger reflects the periodically inefficient water removal at the depropanizer charge accumulator, as well as consequent interference with operation of the entrainment separator, which has already been described. There is little doubt that, with water substantially eliminated from the charge stream, future corrosion will be negligible in this exchanger.

Evidence was also found that water removal was not complete, and that corrosion had not been altogether stopped in the depropanizer reboiler. This reboiler contained excessive deposits of sludge and evidence of slight corrosion on the bottom tubes. The corrosion, however, was not so severe as had formerly been experienced, and it was not necessary to retube the bundle. As in the case of the depropanizer charge-bottoms exchanger, it is felt that the remaining corrosion in this case is largely the result of occasional inadequate water removal at the depropanizer charge accumulator and at the entrainment separator. As measures are taken to increase separator efficiency in streams that feed the depropanizer accumulator, the intermittently high load on the depropanizer entrainment separator will be eliminated. Depropanizer reboiler corrosion then should be reduced to minor proportions.

Excellent corrosion reduction had occurred in the debutanizer reboiler, although large quantities of sludge deposits again were found in this vessel. The reboiler tubes were not corroded at all, even at the bottom of the bundle, where they had been surrounded by sludge, because of the absence of water from the reboiler. The water-removal program is indicated as successful in eliminating severe corrosion at this reboiler, where formerly attack was intolerable.

After no accumulation for two years, the re-appearance of substantial amounts of sludge deposits in the reboiler was surprising. This re-occurrence may be explained by the fact that there is now a lack of water in sufficient quantity in the reboiler to flush deposits from the bundle to the outlet nozzle.

There were two immediate operational benefits which resulted when the driers had been put in operation. These are mentioned as indicative of unexpected advantages—actually having no connection at all with corrosion—which may result from a corrosion-control program.

Operational Benefits

One benefit is the reduction of caustic consumption at the gas plant. It was necessary to charge the debutanized gasoline caustic scrubber with fresh caustic at least every other day, largely because of dilution of caustic with excess water which passed through the gas plant. Initiation of the water-removal operation immediately stabilized the consumption of caustic in this scrubber, and it was not necessary thereafter to recharge with fresh caustic more than once a month.

A second benefit was distinctly improved operation of both the depropanizer and the debutanizer towers. This had been somewhat erratic because of water accumulation and because of slugging into the reboiler. Water drainage through the reboilers caused by notching of baffle plates, as well as the removal, later on, of entrained water from the feed stream eliminated this difficulty.

It is pertinent to review the economic justification for the installation. Experience previous to the installation of entrainment separators established a cost of approximately $1.20 per square foot per year—this for direct material and labor charges for maintenance of heat-exchange surface in the gas plant. The total installation cost of the separators and the chemical injection equipment amounted to $0.45 per square foot of gas-plant exchanger surface. Results to date leave no doubt that the installation is economical, based on direct maintenance costs alone. Larger and less tangible economic benefits have also resulted from improved continuity of operation.

Conclusion

This paper has reviewed the corrosion-control measures for the gas plant of a modern catalytic cracking unit. Refinery inspection department findings and laboratory data concerning gas-plant streams were used to assess the degree and nature of corrosion. No matter where corrosion occurred, it was found to be almost entirely associated with excessive water present in the system.

A corrosion-control program was put into effect that consisted, for the most part, of water-removal measures at key points in the gas plant. Findings have been discussed that indicate the success to date of the water-removal program.

The authors wish to acknowledge gratefully the cooperation of W. S. Bedell for having supplied records and for having contributed to the interpretation of inspection findings. The authors also wish to express appreciation to The Pure Oil Company for permission to prepare and publish this report.

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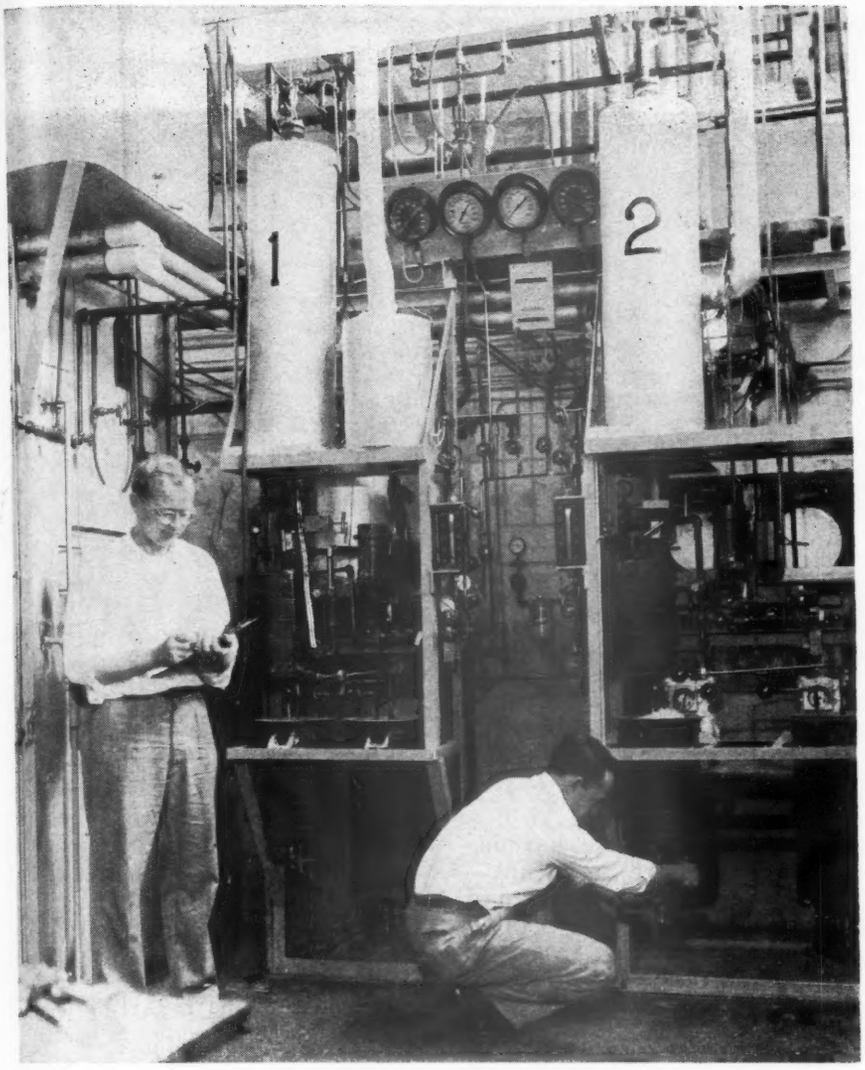

FIG. 1. Houdriforming pilot unit.

HOUDRIFORMING

A CONTINUOUS PROCESS FOR REFORMING PETROLEUM NAPHTHAS

C. G. KIRKBRIDE*

HOUDRIFORMING is a catalytic process for reforming petroleum naphthas to aromatic concentrates and high octane gasoline. Dual-function catalysts have been developed for this process. These catalysts are very selective for (1) the dehydrogenation of C_6 ring naphthenes, (2) the dehydro-isomerization of alkyl cyclopentanes, and (3) the isomerization of normal and slightly branched paraffins into highly branched paraffins. Essentially no hydrocracking occurs and, therefore, substantially pure hydrogen (97%+) is produced. The catalysts are not affected by sulfur compounds including thiophene. *The process is non-regenerative, although for flexibility of operation and for protection in case of error in operation the catalyst can be regenerated in place.* The process is in an advanced state of pilot plant development. Detailed process design and mechanical engineering for commercial scales operation are underway.

The selective transformation of the constituents of naphthas without cracking has been the object of reforming for many years. Thermal reforming,[1] hydroforming,[2] and catalytic reforming processes employing platinum catalysts[3] have shown the trend for more specific reactions. In the experimental work to be presented, the effect of changing catalyst properties will be discussed.

Houdriforming can produce maximum yields of benzene, toluene, and xylene from specific fractions of a crude. Production of benzene and toluene will be discussed from an experimental and theoretical viewpoint. The production of high yields of high octane gasolines from straight-run naphthas by Houdriforming will then be discussed. The isomerization function of the catalyst in addition to the dehydrogenation function permits the reforming of low octane naphthas to high yields of very high octane number product.

Houdriforming for Aromatic Production

Experimental. The Houdriforming process can be visualized by considering typical pilot plants in the Houdry laboratory shown in Figs. 1 and 2, and the simplified flow diagram, Fig. 3. These pilot plants represent, respectively, "isothermal" and "multibed adiabatic" units.

In life tests (30-50 days of continuous operation without regeneration or loss of catalyst activity) in multibed adiabatic units, different charge stocks were processed at widely varying conditions over the same catalyst. A charge stock comprising a 150-220 F cut of an East Texas type naphtha was used as a base stock and was run periodically at fixed conditions to check the catalyst activity. The properties and composition of this stock are presented in Table 1.

The availability of naphthenes in this charge stock would allow a stoichiometric yield of 48.4 volume per cent aromatics based on the charge; this includes the aromatics originally

TABLE 1.
Inspection of base charge stock for aromatic production.

Boiling range*	150-220 F
Gravity, API	60.2
Distillation, ASTM	
IBP, F	162
10%	180
30%	186
50%	190
70%	196
90%	204
Dry point	215
Composition	
Benzene	1.8
Toluene	4.2
Methyl cyclopentane	5.1
Cyclohexane	14.3
Dimethyl cyclopentanes	9.2
Methyl cyclohexane	22.7
Paraffins	42.7

*Temperatures are the cut points during preparation of this stock using a 20 plate distillation column.

*Houdry Process Corporation, Marcus Hook, Pennsylvania.

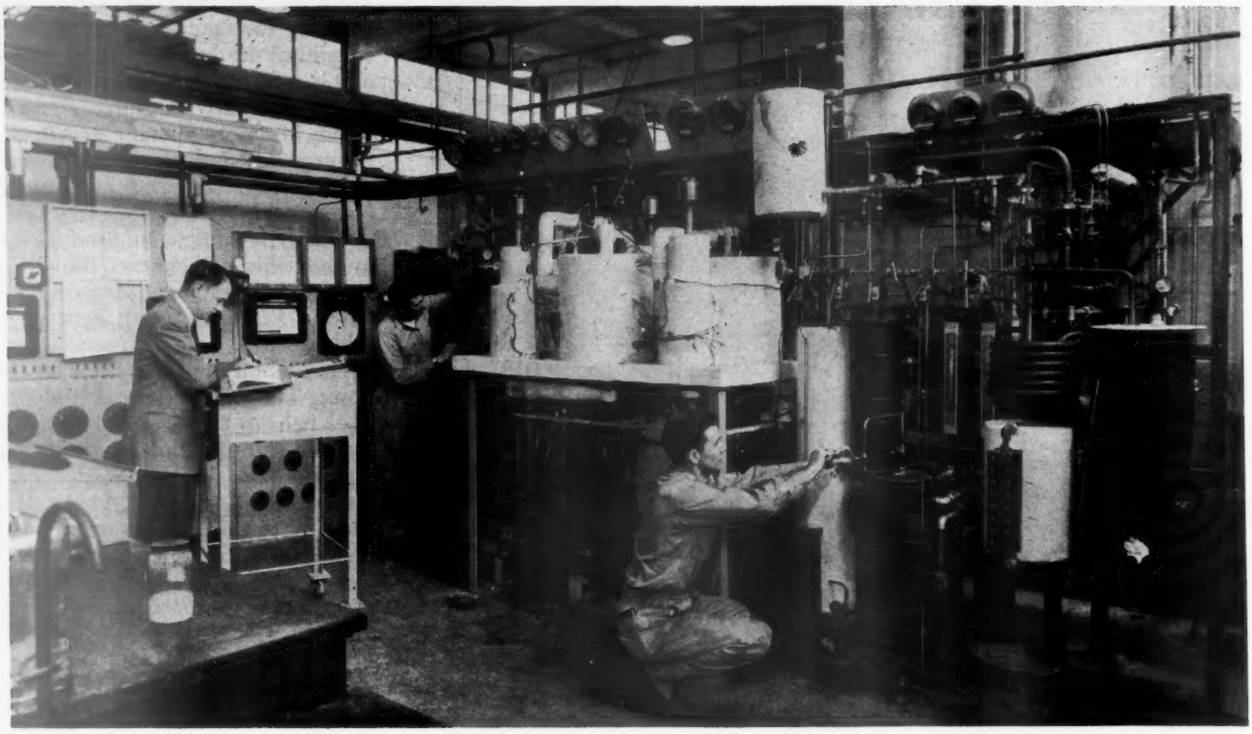

FIG. 2.

present in the charge. Stoichiometric conversion of the naphthenes, as will be evident later, is not directly attainable because of thermodynamic equilibrium considerations.

The yields of aromatics produced from this charge stock are summarized in Table 2. The yield of aromatics increases to very high levels as the severity of operating conditions is increased. A significant fact is that the hydrogen recycle gas and off-gas from the unit consists of 97.5-98.5 volume per cent hydrogen at all conditions. In this operation gas separation was effected in a simple pressure separator at atmospheric temperature. The yield of hydrogen is better than 90 per cent of theoretical based on conversion of naphthenes to aromatics. These facts indicate that the catalyst is very selective and promotes very little hydrocracking at the operating conditions employed.

The base charge stock described previously was processed at a fixed set of conditions. Check runs were made with this stock at the same conditions after 18, 24, and 35 days of continuous operation. No change in the activity of the catalyst could be detected at any of these check intervals. For the investigation of process variables, a multibed adiabatic unit has been used.

The same unit has been used to obtain engineering design data. Typical of the type of information obtained is the temperature pattern for the first reactor shown in Fig. 4. Similar patterns prevail in succeeding reactors. The temperature drop decreases for each succeeding reactor, however, as will be seen later. The number of reactors put in series is dependent on the particular stock to be processed and the type of operation to be carried out.

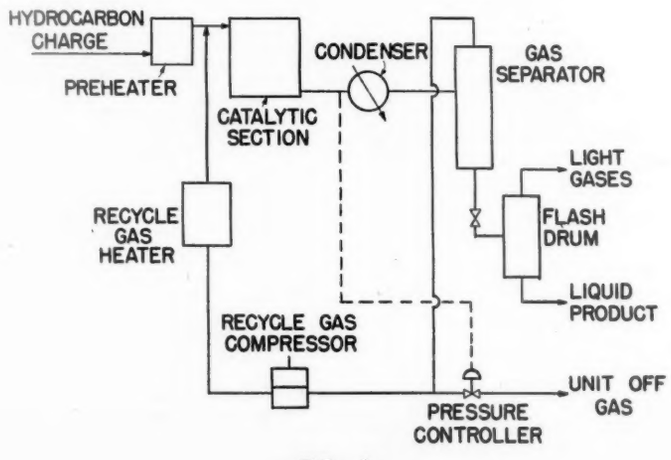

FIG. 3.

Other stocks investigated have included C_6 fractions containing up to 57 per cent methyl cyclopentane. In addition to quantitative dehydrogenation of cyclohexane present, major proportions of the methyl cyclopentane have been converted to benzene, depending on severity of operations and nature of feed.

Theoretical. Thermodynamic considerations are significant in aromatics production because they limit the per cent of products that can be attained under various operating conditions.

Consider the two reactions involved in benzene formation:

(1) C_6H_{12} (cyclohexane) $= C_6H_6 + 3H_2$; $Kp^{(1)} = \frac{(pH_2)^3(pC_6H_6}{(pC_6H_{12})} = 10_6$ at 950°F

(2) C_6H_{12} (cyclohexane) $= C_6H_{12}$ (methyl cyclopentane); $Kp^{(2)} = \frac{^{P}\text{methyl cyclopentane}}{^{P}\text{cyclohexane}} = 12$ at 950°F

The pressure of hydrogen obviously

TABLE 2. Houdriforming operations processing a 150-220 F East Texas type naphtha for benzene and toluene production.

	Order of increasing severity		
	1	2	3
Liquid product C_4-free, volume per cent of charge	93.2	92.2	91.5
Aromatics in liquid product, volume, per cent	38	45	48
Conversion of naphthenes to aromatics, per cent	70	84	90
Unit off-gas produced, SCF/bbl	1160	1310	1360
Hydrogen content of off-gas, volume, per cent	98.5	98	97.5

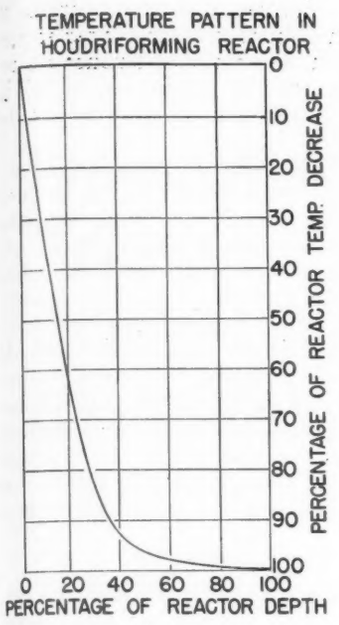
TEMPERATURE PATTERN IN HOUDRIFORMING REACTOR
PERCENTAGE OF REACTOR TEMP. DECREASE
0 10 20 30 40 50 60 70 80 90 100
0 20 40 60 80 100
PERCENTAGE OF REACTOR DEPTH

FIG. 4.

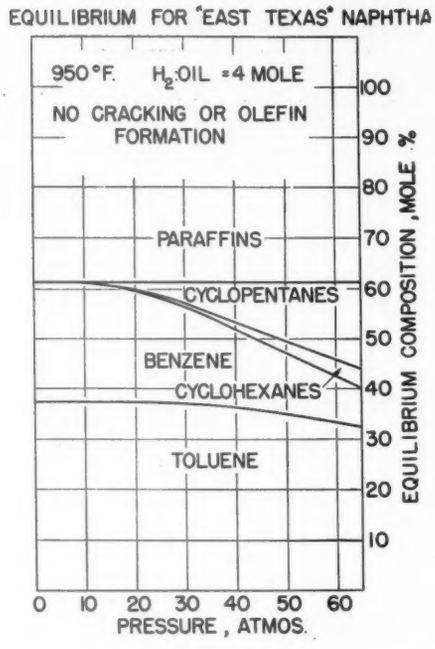

FIG. 5.

has a very powerful influence on the C_6H_6 to C_6H_{12} mol ratio in the product and indeed, in the pressure range studied, is the limiting factor for benzene production at a given temperature. It is evident from Fig. 5 that at pressures above 300 psi the equilibrium amount of benzene falls off rapidly, while the amounts of cyclohexane and cyclopentanes concommitantly increase. On the other hand, the equilibrium toluene concentration remains high to a much higher pressure than for benzene. Fig. 5 is based on thermodynamic data from API Project 44[4] and represents the equilibrium condition for an East Texas type naphtha at a H_2/oil mol ratio of 4 at 950 F, olefin formation not being permitted. Under the present circumstances, pressures may be substituted for fugacities satisfactorily.

Temperature affects the several equilibria to a critical degree. This is shown by Fig. 6 in which is presented (for a H_2/hydrocarbon mol ratio of 5 and a total pressure of 300 psi) the relative amounts of benzene-cyclohexane and benzene-cyclohexane-methyl cyclopentane. It is evident that isomerization to form methyl cyclopentane offers an important reaction from the standpoint of benzene yield.

The maximum yields obtainable in adiabatic operation can be calculated on the basis of thermodynamic equilibrium, the heat of reaction, and the heat capacity of the reaction constituents. Dehydrogenation of naphthenes is highly endothermic and this heat is supplied by the sensible heat of the reaction constituents. A temperature-conversion line can be calculated, starting at reactor inlet conditions of temperature and composition. When plotted on the same figure as the equilibrium composition, this line will intersect the equilibrium line at a point which then represents the maximum amount of aromatics obtainable in a single adiabatic reactor. This is shown in Fig. 6 for cyclohexane dehydrogenation with a reactor inlet temperature of 925 F.

In actual operation, dehydrogenation and isomerization reactions of all the naphthenes to respective aromatics must be considered. Heat carried by paraffins is substantial. The adiabatic operating lines and thermodynamic equilibrium for the stock, specifications of which are given in Table 1, are shown in Fig. 7. The effect of reactor inlet temperature and number of reactors is clearly illustrated. It was found experimentally that individual reactor operation of Houdriforming followed closely the theoretical abiabatic operating lines.

Ordinarily the process is non-regenerative for the production of aromatics from a single wide cut charge stock. For most severe conditions on unusually wide boiling range charge, however, a catalyst deposit may accumulate slowly and the ability of the catalyst to be regenerated provides maximum flexibility. Thus a non-blocked-out operation can be employed for the simultaneous production of benzene, toluene, and xylenes.

Gasoline Production

Upgrading of motor gasoline by Houdriforming is accomplished by 4 reactions: Conversion of 6-membered ring naphthenes to aromatics, dehydro-isomerization of alkyl cyclopentanes to aromatics, isomerization of straight chain or slightly branched paraffins to highly branched paraffins, and desulfurization of naphtha, which improves the lead response. The isomerization function of the catalyst for converting low octane paraffins to high octane branched chain paraffins is of

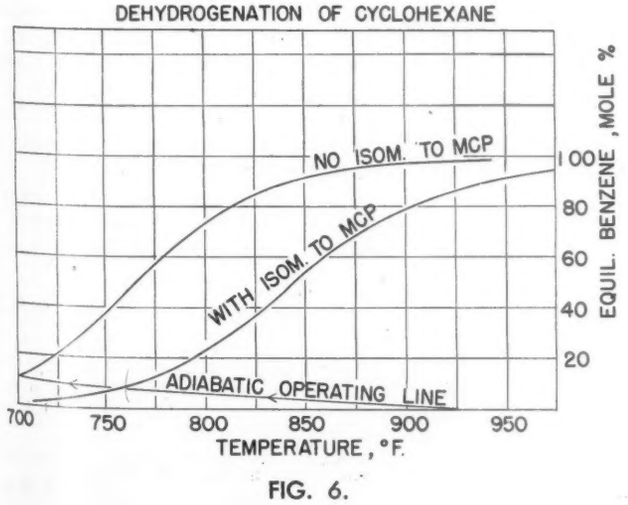

FIG. 6.

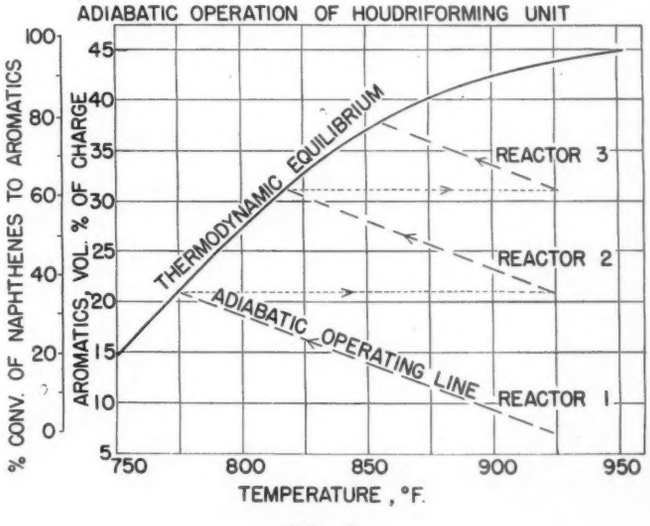
ADIABATIC OPERATION OF HOUDRIFORMING UNIT
% CONV. OF NAPHTHENES TO AROMATICS
AROMATICS, VOL. % OF CHARGE
100 80 60 40 20 0
45 40 35 30 25 20 15 10 5
THERMODYNAMIC EQUILIBRIUM
REACTOR 3
REACTOR 2
ADIABATIC OPERATING LINE
REACTOR 1
750 800 850 900 950
TEMPERATURE, °F.

FIG. 7.

great importance in attaining the high yield of high octane reformate.

Conversion of naphthenes to aromatics improves the octane rating only in the case of higher boiling naphthenes. Thus, the conversion of methyl cyclopentane and cyclohexane (F-1 blending value 107 and 110, resp.) to benzene (F-1 blending value 99) actually involved a loss of blending number octane, while the conversion of dimethyl cyclohexane to xylene increases the blending octane number from 68 to 145. In employing Houdriforming for motor gasoline production it is therefore, desirable to use only feed stocks that have been fractionated to include the maximum amount of naphthenes in a boiling range in which octane improvements can be obtained.

In Fig. 8 are shown octane-yield relationships for an East Texas type naphtha after Houdriforming under different operating conditions with different catalysts. The specifications of this naphtha are given in Table 3. Curve A, Fig. 8, represents results obtained with a commercial molybdena-alumina hydroforming catalyst and shows how hydrocracking lowers yield without corresponding octane gain. Also a type of hydrocracking occurs with this catalyst that causes catalyst deposit formation requiring frequent regeneration. Curves B and C were obtained with different Houdriforming catalysts; B has only a dehydration function whereas C has both dehydrogenation and isomerization functions. The differences between these catalysts become most apparent at high octane numbers. It is quite striking also that a 78 volume per cent yield of C_{5+} 3 lb RVP product of 97.3 F-1 clear octane number was obtained with catalyst C.

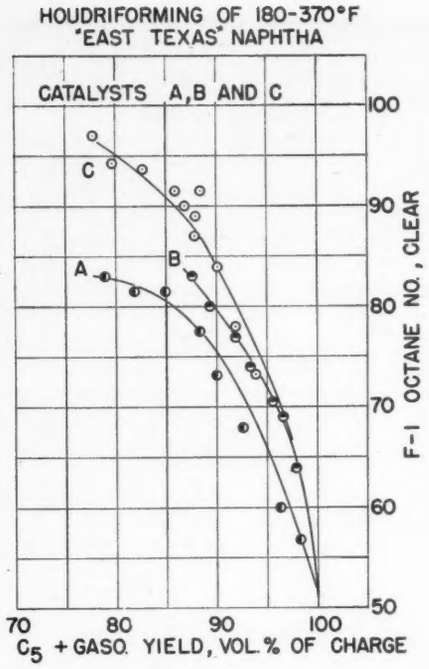

FIG. 8.

All yields and octane numbers in Fig. 8 are for C_4—free gasoline of about 3 lb RVP. Considerable outside butane may bring the gasoline to 10 lb RVP. Overall yield and, to a certain extent, also octane numbers are thereby raised. Catalyst C under proper conditions can produce enough butane to obtain 10 lb RVP gasoline. Catalyst B under all operating conditions and catalyst C under mild conditions, however, give products to which outside butane must be added. Butane produced in Houdriforming and the outside butane required thus compensate for most or all of the valume loss suffered in converting the naphthenes to aromatics. Indeed, as shown in Table 4, the 10 lb RVP gasoline may amount to 100 volume per cent plus of the charge when utilizing added butane.

TABLE 3. Inspection of charge stock for gasoline production.

(East Texas type naphtha)

Boiling range	188–368 F
Gravity, API	55.3
Distillation, ASTM	
IBP, F	188
10%	215
30%	232
50%	252
70%	280
90%	317
Dry point	349
Sulfur, per cent	0.006
Composition	
Paraffins, volume per cent	44
Olefins, volume per cent	0
Naphthenes, volume per cent	42
Aromatics, volume per cent	14
Octane number[3] F-1 Clear	51.2
F-1 + 3 cc. TEL	76.6

As outside butanes are available in most refineries, it is very desirable to eliminate hydrocracking as far as possible. In the event that butanes are required for the production of 10 lb RVP gasoline, hydrocracking can be effected.

In Table 4 are shown yields and octane numbers obtained by Houdriforming East Texas type naphtha (previously described) at three sets of operating conditions. These data illustrate how an increase in severity of operating conditions will raise octane number at expense of yield. At desirable operating conditions the usable catalyst life is principally a function of external poisoning by impurities in the feed stock. With proper control of these no loss in activity has been experienced in pilot plant runs.

Conclusion

Houdriforming is a continuous catalytic reforming process which is applicable to the production of aromatics as well as to the production of high octane number gasolines. A dual-function catalyst has been developed which promotes, very selectively, the conversion of naphthenes to aromatics and low octane number paraffins to higher octane number paraffins. The process is non-regenerative, although for flexibility of operation and for protection in case of plant failure the catalyst can be regenerated in place.

Houdriforming for aromatic production is limited principally by thermodynamic considerations. Substantially equilibrium amounts of benzene, toluene, and xylene can be obtained from the 5- and 6-membered ring naphthenes contained in naphtha stocks.

Acknowledgment

The development of the Houdriforming catalysts is a result of the fundamental research which the Houdry Process Corporation has carried on for a number of years. Heinz Heineman, T. H. Milliken, G. A. Mills, and A. G. Oblad are primarily responsible for the success of this program.

It is appropriate that credit be given to J. C. Dart, J. W. Schall, T. A. Burtis, and D. H. Stevenson for the successful pilot plant development of the Houdriforming process.

The contributions of other members of the staff are also acknowledged.

TABLE 4. Houdriforming of East Texas type naphtha.

188–368 F, F-1 Clear 51.2 F-1 + 3 cc. TEL 76.6

	Condition 1	Condition 2	Condition 3
Yield, C_5+, Volume per cent of feed	77.7	88.5	96.0
Weight per cent of feed	82.8	92.7	98.0
C_4, volume per cent of feed	17.2	6.1	1.2
F-1 clear, 3 lb. RVP gaso	97.3	91	71
F-1 + 3 cc. TEL, 3 lb. RVP gaso	Iso-octane + 0.3 cc TEL	98	87
Yield, 10 lb RVP gaso. calc., volume per cent	86*	98**	106***
F-1 clear, calc.	98	92.5	75
F-1 + 3 cc. TEL, calc.	>100	99	89.5

* Excess butane over 10 lb. RVP gasoline is 8.9 vol. per cent.
** Outside butane required for 10 lb RVP gasoline is 3.4 per cent.
*** Outside butane required for 10 lb RVP gasoline is 8.8 per cent.

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Gasoline Plant Absorber Performance†

R. A. KING*

OVER a period of years numerous papers have been written on the subject of the operation and design of natural gasoline absorbers. The optimum temperature, pressure, tray design, and number of trays is still an open question. Probably the reasons that more progress has not been made in establishing a uniform standard absorber that will operate efficiently under all conditions are: (1) the relative cost of the equipment, (2) the difficulty encountered in testing absorbers under identical conditions, and (3) the even more difficult task of properly analyzing the gas samples in the laboratory to detect minute quantities of gasoline components still remaining in the dry gas. This paper is written, not to present a new design of absorber or method of operation, but to review some of the control methods of absorbers and the factors affecting efficient operation.

Testing the Quality of Lean Oil

The methods for testing of lean oil are covered in detail in the California Natural Gasoline Association Bulletin No. 5-343 published in 1934. These tests also include those used in determining the quality of absorption oil when received from the refiner. They are B.S. and B. shrinkage by water, sulfuric acid, and sodium hydroxide, molecular weight, and steam emulsion. Further tests are outlined for use of the plant operator and laboratory. These include the gum content, gravity, viscosity, and the hempel distillation. These tests enable the operating personnel to maintain adequately the lean oil in good condition to obtain the maximum gasoline extraction.

Additional tests have been developed since the publication of Bulletin No. 5-343. Refinements and alterations have been made on some of the existing tests. In one case, the vapor pressure method has been revised to speed up the operation and provide results that are presumed to be superior to those obtained by the standard vapor pressure method outlined in the bulletin. The engler distillation has been modified so that a close control of the distillation unit may be obtained by its use. A method has been developed whereby a low temperature fractional analysis can be obtained under carefully controlled conditions. The sample of lean oil is withdrawn from the circulation system directly into a 500 ml two-hole stopper flask to which 50 c.c. of granular calcium chloride has previously been added. The oil is allowed to flow through the flask from bottom to top until the flask is thoroughly purged. Pinch clamps are then placed on the two connections to the flask and the sample transferred to the laboratory for analysis. The fractionating column is evacuated down to the pinch clamp on the connection that extends to the bottom of the flask. The upper connection is then opened to the air and a sample drawn into the column (75 to 100 ml), which is free of water and air contamination. The entire distillation is conducted at 40 mm absolute pressure and a 1/10 gallon measuring bottle may be used to accurately measure the overhead vapor.

The above test method has been outlined because the operator believes that a fractional analysis will aid in providing valuable information to assist in maintaining the lean oil in good condition.

Lean Oil Characteristics Affecting Absorber Performance

After the characteristics of an absorption oil have been determined, the responsibility rests with the laboratory personnel or operator to correctly apply the findings to the plant operation. Knowledge of the viscosity of an absorption oil will aid the engineer in calculating flow rates and pipe sizes, but does not appreciably affect the plant operation. For this reason viscosities may be omitted from the routine tests unless a special problem is encountered.

The modified engler distillation will, if properly conducted, permit the operator to control the fractionating still and secure a well-fractionated lean oil. The initial boiling point of the lean oil is the controlling factor in determining whether or not the still is operating at peak performance. Should the initial boiling point drop below 350 F, adjustments are made in the still operation. One operator has at times allowed the per cent distilled below 380 F to reach 10 per cent or more without any apparent detrimental effects on the dry discharge gas, providing the initial boiling point is higher than 350 F.

Gum forming materials allowed to accumulate in the lean oil accelerate the deposition of carbon in the heat exchanger equipment and in some cases in the still. Therefore, the test for gum content is valuable to the operator in that a constant check can be made on the reconditioning lean oil still. The gum content of the lean oil should be less than 100 lb per 1000 gal and can be maintained as low as 25 lb per 1000 gal. If the lean oil has become contaminated with compressor cylinder oil or crude oil from the field, it may be necessary to make a deeper cut in the lean oil by changing the reconditioning lean oil still operation. A good reconditioning still practically eliminates the necessity for changing oil in the system because of impurities. Also, a closer boiling range lean oil can be maintained.

The analysis of a lean oil will usually reveal the presence of light ends in lean oil that other tests fail to detect. As shown in Table 1, only 2 of 13 plants tested failed to show gasoline components lighter than hexanes. One of these plants was operating a 1500 lb gage absorber and the other plant a 45 lb gage absorber. Kremser, who has presented the well known absorption factor $A = \frac{3.156\ DPG}{M_p}$, which can be used to calculate most absorber efficiencies, has also presented a formula for calculating the loss in the dry discharge gas when the lean oil is improperly stripped. This formula is $Y_1 = 0.7\ \frac{n_o}{P}$ where Y is the gasoline content in gallons per 1000 cu ft of the discharge gas, due to a vapor pressure of the lean oil amounting to n_o mm of Hg at absorber temperature. P is the absorber pressure in pounds per square inch absolute. This formula can be used when vapor pressure determinations are conducted on the lean oil. In using this formula, the assumption must be made that the

†Presented before California Natural Gas Association, 1950.

*Union Oil Company of California.

gasoline component or components causing this vapor pressure are of the same order in all lean oils. The fractional analysis not only shows the components that could possibly cause a loss in the discharge gas, but also shows the magnitude of that loss. This loss will be discussed later in the paper. Control of the molecular weight of the lean oil is beyond the scope of the laboratory or operator. Possibly special runs of lean oil with a narrower boiling range could be ordered from the refiner. The possibility of obtaining lower molecular weight lean oil for use in high pressure plants should be investigated. The addition of cycle compounds containing more mols per unit volume of liquid could raise the over-all absorber efficiency. It is questionable whether special grades of lean oil at higher cost would be economical where the plant lean oil consumption is high.

Normally, a heavier lean oil will have an added advantage over the light oil from an operating viewpoint in that the entrainment of oil in the dry gas is less, thereby reducing the lean oil consumption. Actual demonstrations viewed in a plastic model absorber have shown that the heavier oils will form a greater depth of foam on the tray than the lighter oils. This would be a definite advantage in an absorber where there is an insufficient number of trays or the tray design is inadequate for the oil and gas rates.

Impurities in the wet intake gas to the absorber occasionally contaminate the lean oil, causing an accumulation of gum forming materials and carbon deposits. These impurities in the lean oil do not interfere with the absorber operation directly but frequently cause the still and heat exchangers to become coated with carbon, which lowers the efficiency of the equipment. Sometimes the carbon will form in the lean oil so rapidly that the conventional reconditional still cannot effectively remove the accumulation. Efforts should be made to determine the cause of the carbon formation and install the necessary equipment to treat the intake gas to remove the impurities. One operator who was having excessive carbon formation installed an iron oxide bed ahead of the absorber to remove the hydrogen sulfide from the wet gas. The H_2S content of the gas was approximately 1.0 grain H_2S per 100 cu ft wet gas. This installation materially reduced the carbon content of the lean oil and the color of the oil gradually changed from black to a straw color. Although the condition cited above does not directly concern the absorber operation, the lean oil can become so contaminated that shut down periods may be necessary.

TABLE 1. Fractional analyses of lean oils.

Absorber pressure #ga.	45 Liq. %	45 Liq. %	90 Liq. %	90 Liq. %	75 Liq. %
Methane					
Ethane					
Propane					
Iso-butane		0.0320	0.0056		0.0513
N-butane	0.0600	0.0630	0.0273	0.0055	0.0764
Iso-pentane	0.0500	0.0720	0.0380	0.0063	0.1358
N-pentane	0.1000	0.1080	0.0815	0.0188	0.1448
Hexanes & heav.	99.7900	99.7250	99.8476	99.9694	99.5917
Total	100.0000	100.0000	100.0000	100.0000	100.0000
Absorber pressure #ga.	45 Liq. %	45 Liq. %	30 Liq. %	475 Liq. %	475 Liq. %
Methane					
Ethane					
Propane			0.0202		
Iso-butane		0.0003	0.0151	0.0074	0.00
N-butane		0.0092	0.0175	0.0071	0.0082
Iso-pentane	Trace	0.0107	0.0406	0.0289	0.0381
N-pentane	Trace	0.0141	0.1039	0.0285	0.0329
Hexanes & heav.	100.0000	99.9597	99.8027	99.9281	99.9208
Total	100.0000	100.0000	100.0000	100.0000	100.0000
Absorber pressure #ga.	450 Liq. %	450 Liq. %	1500# Liq. %		
Methane					
Ethane					
Propane	0.0384				
Iso-butane	0.0412				
N-butane	0.0397	0.0086			
Iso-pentane	0.0410	0.0570			
N-pentane	0.0556	0.0632			
Hexanes & heav.	99.7841	99.8712	100.0000		
Total	100.0000	100.0000	100.0000		

TABLE 2. Absorber discharge gas losses at various pressures. 99+ % iso-butane theoretical oil/gas ratio assumed.

Pentanes and lighter Liq. %	Hexanes and heavier Liq. %	Gravity °API	Maximum losses possible with contamination shown 30# Abs.	100# Abs.	500# Abs.
0.2100	99.7900	39.0	0.210	0.105	0.021
0.2750	99.7250	39.5	0.275	0.138	0.028
0.1524	99.8476	39.0	0.152	0.076	0.015
0.0306	99.9694	39.1	0.031	0.016	0.003
0.4083	99.5917	38.3	0.408	0.204	0.041
Trace	100.0000	39.0	.....	.....	.....
0.0403	99.9597	38.2	0.041	0.021	0.004
0.1973	99.8027	37.2	0.197	0.099	0.020
0.0719	99.9281	37.4	0.072	0.036	0.007
0.0792	99.9208	....	0.079	0.040	0.008
0.2159	99.7841	38.5	0.216	0.108	0.022
0.1308	99.8712	38.5	0.129	0.065	0.013
0.0	100.0000	35.5	.....	.....	.....

Absorber Efficiencies and Economics

All absorber operations must be considered from an economical viewpoint. The operator must be able to balance the high cost of efficient equipment and operating cost with the profit obtained by extracting the last gallon of gasoline from the discharge gas. Assume, for instance, that a fractionating still is unable to remove the last trace of natural gasoline in the lean oil. Table 2 shows the maximum loss in butanes and pentanes that can be expected at different absorber pressures for the lean oil analyses shown. This is assuming that sufficient oil is circulated to obtain a 99 per cent plus iso-butane extraction. The plant

TABLE 3. Data from crude oil absorption plant.

	Absorber intake gas Mol %	GPM	Gal/24 hr	Absorber discharge gas Mol %	GPM	Gal /24 hr
H_2O, CO_2, air	5.70			5.60		
Methane	69.41		6012	85.91		5622
Ethane	9.42		1222	6.74		611
Propane	10.06	2.760	1410	1.02	0.280	108
Iso-butane	1.58	0.515	263	0.17	0.055	21
N-butane	1.93	0.607	310	0.24	0.075	29
Iso-pentane +	1.90	0.733	375	0.32	0.117	45
	100.00	1.855	9592	100.00	0.247	6486

	Conditioned crude oil to absorber Liquid %	Enriched crude oil from plant Liquid %
Ethane	0.09	0.10
Propane	0.50	1.87
Iso-butane	0.20	0.71
N-butane	0.53	1.02
Iso-pentane +	98.68	96.30
	100.00	100.00
API gravity	26.0°	27.5°
Reid V.P.	4.2#	9.4#
	Absorber efficiency %	Plant efficiency %
Propane	92.34	82.24
Iso-butane	92.02	87.97
N-butane	90.65	86.15
Iso-pentane +	88.00	84.41

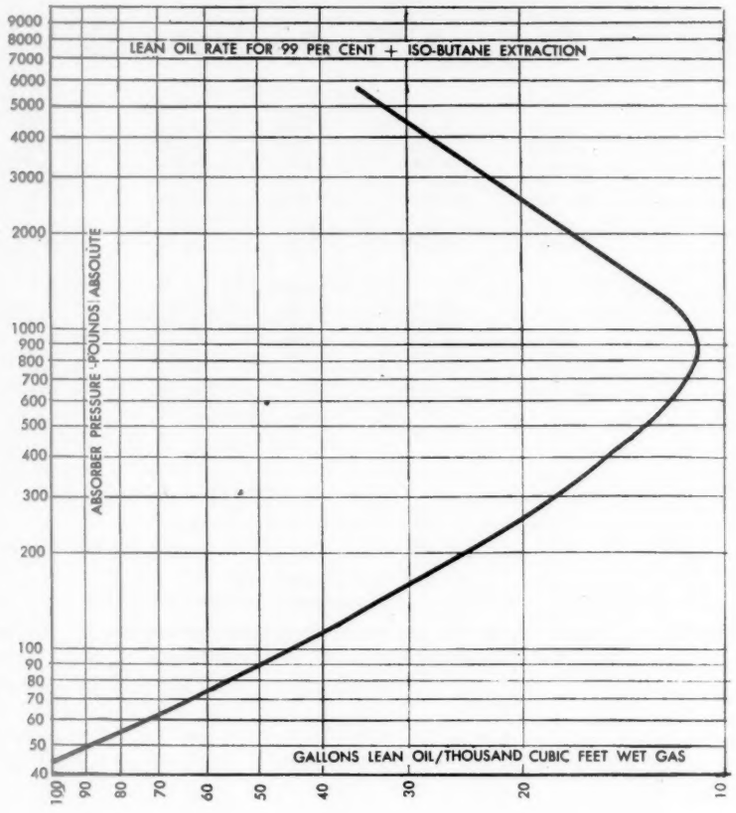
LEAN OIL RATE FOR 99 PER CENT + ISO-BUTANE EXTRACTION
ABSORBER PRESSURE - POUNDS ABSOLUTE
GALLONS LEAN OIL/THOUSAND CUBIC FEET WET GAS

FIG. 1. Oil rate for maximum i-butane and heavier recovery.

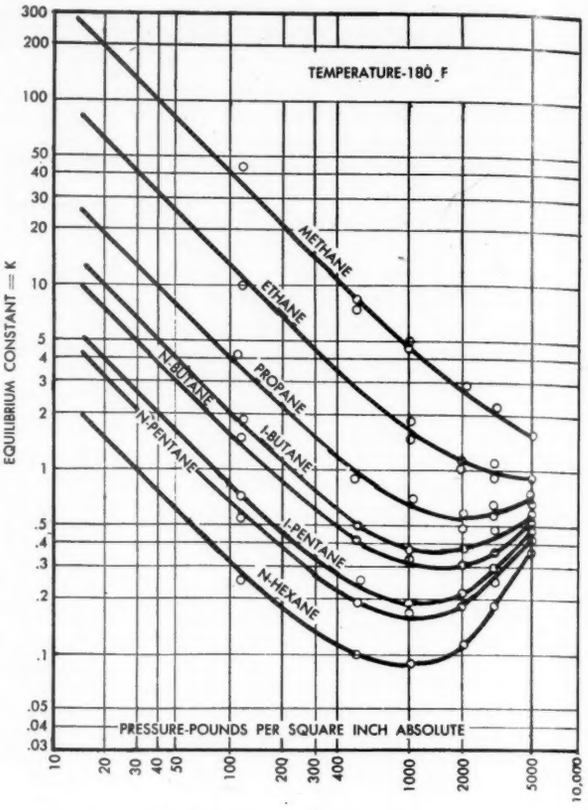

FIG. 2. Equilibrium constants for hexanes and heavier at 180 F.

lean oil analysis shown in Column 1 could yield a maximum absorber loss in the dry gas of 0.21 gal per MCF in a 30 lb gage absorption system and a loss of 0.021 gal per MCF in a 500 lb absorber. Apparently a close control of lean oil saturation in a high pressure plant is relatively unimportant while the last traces of gasoline should be removed from the lean oil in the 30 lb gage plant to minimize the gasoline losses. The highest loss shown was in a 30 lb absorber and the dry gas analysis in this plant also showed a high iso-butane and heavier gasoline loss. The fractional analysis of a lean oil is valuable in that the engineer and laboratory technician can readily determine the degree of loss in a dry gas caused by improper stripping of the lean oil. Before any attempt is made to determine the tray efficiency of any absorber, the condition of the lean oil should be ascertained, particularly in the low pressure plants.

Table 3 shows the loss in the dry discharge gas in a crude oil absorption plant where 25 API gravity crude oil is used as an absorbent. This crude oil with a Reid vapor pressure of 4.2 lb is conditioned previous to entering the absorber at 250 lb. The loss in iso-butane and heavier gasoline in the discharge gas is 0.247 gal per MCF. At present, the wet gas is entering the base of the absorber directly from the compressor without cooling. This gas temperature of 166 F has increased the base temperature of the absorber with a resultant decrease in absorber efficiency. When this condition has been corrected, the discharge gas yield should be lower than that shown. This operation illustrates what can be accomplished with high pressure absorption even though the absorbent is highly saturated with the components to be extracted. Also the mol concentration of the crude oil is low compared to the conventional lean oil.

Fig. 1 shows the oil rate per MCF required for maximum iso-butane and heavier extractions at various absorber pressures. At 30 lb gage and 100 F, 100 gal per MCF is required and at 500 lb gage, 13 gal per MCF is necessary. At some point above 500 lb gage (probably 800 lb), the oil rate per MCF no longer decreases but an increase in oil rate is required to obtain the same extraction. Actually the equilibrium constant K for iso-butane at 100 F reaches its lowest value at 900 lb absolute pressure. Any further increase in pressure above 900 lb or reduction in temperature below 100 F should require additional oil to obtain the same iso-butane extraction. On Fig. 2 are shown the equilibrium constants for hexanes and lighter components at 180 F. At 900 lb gage the normal hexane equilibrium constant or K value no longer reduces but actually increases in value with increased pressure. Consequently, additional oil is required to offset this increase in K value. If the Kremser equation holds true for 1500 lb absorption at 180 F, then 11 gal of lean oil per MCF would be required for maximum extraction of iso-butane and heavier gasoline. Fig. 2 shows that at 180 F iso-butane has its lowest value of K or equilibrium constant at 1500 lb gage. Therefore, the maximum iso-butane should theoretically be extracted at 180 F in a 1500 lb plant and require the least oil circulation rate. If it were possible to extract at higher temperatures in high pressure plants, there would be a large saving in fuel. Insufficient work has been done to prove the feasibility of operating at higher temperatures but one test on a 1500 lb absorber showed a lower discharge yield with a lean oil temperature of 110 F than at 70 F. All other absorber conditions were identical.

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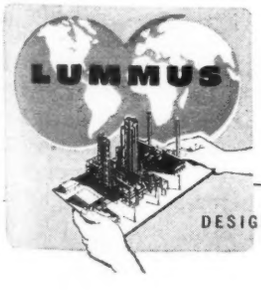

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Equipment Influencing Absorber Performance

The design of the absorber is the controlling factor in obtaining efficient extraction. A discussion of the tower design is beyond the scope of this paper, but several major items can be reviewed. If the tower is overloaded, the gas will carry out entrained oil. If the tower is underloaded, the fluid will be relatively quiet on the tray and poor contact between oil and gas will result. If the tower lacks sufficient trays, the efficiency will be low. Table 4 illustrates the difference in yields obtained in a 45 lb gage absorber with the same oil-gas ratio but at varying oil and gas rates. The only conclusion that can be derived from this test is that the higher the gas velocity through the tower, the higher the efficiency, providing the gas does not carry out entrained oil. If the gas stream could be broken up into very minute bubbles or a foam formed on each tray, higher extraction efficiencies would possibly result.

Operation of Plant and Its Effect on Absorber Performance

An absorption oil that is allowed to build up in light ends to 10-20 per cent distilled below 380 F will not materially affect the high pressure plant. The same condition existing in a low pressure plant will yield an increased loss in gasoline in the discharge gas. Frequently the top temperature of fractionating stills is controlled to maintain a definite end point gasoline. If a quantity of condensate is suddenly pumped into the still with the reflux, then the heavy ends of the condensate, being unable to vaporize with the vapor stream, will remain in the lean oil. Experience has shown that a constant reflux rate to the still will allow any heavy hydrocarbons that may periodically be present in the plant production to vaporize. The top temperature will rise and fall as the composition of the material fractionated changes. Occasionally, when the weather changes abruptly, there may be a radical change in the condition of the lean oil. Therefore, the lean oil should be checked regularly by use of one of the tests outlined to maintain the oil in good condition. Normally, the steam agitation rate is considered to be adequate for the operation but sometimes a plant will be found where excessive steam is used for agitation. Probably in cases like this no tests were ever made to determine the minimum steam required. Any reduction in steam agitation is a direct saving in boiler fuel and will also reduce the heat load on the cooling equipment.

TABLE 4. Absorber operation at various operating rates.

Operating data	Test No. 1	Test No. 2	Test No. 3
Absorber intake, MCF/day	5,093	7,608	10,145
Absorber discharge, MCF/day	4,590	6,855	9,141
Oil rate, gal/hr	11,000	16,500	22,000
Oil-gas ratio	51.9	52.1	52.0
Oil to absorber, F	77	78	78
Oil from absorber, F	85	87	87
Gas to absorber, F	75	75	76
Gas from absorber, F	79	79	79
Gas to absorber, psi.ga	36.7	36.6	37.7
Gas from absorber, psi.ga	34.5	33.5	33.5
Extraction data			
	Test No. 1	Test No. 2	Test No. 3
Abs. intake propane, GPM	1.756	1.756	1.756
Abs. intake propane, Gal	8,994	13,360	17,815
Abs. discharge, propane GPM	1.309	1.287	1.281
Abs. discharge propane, Gal	6,008	8,822	11,710
Abs. efficiency propane, per cent	32.82	34.04	34.27
Abs. intake iso-butane, GPM	0.313	0.313	0.313
Abs. intake iso-butane, gal	1,594	2,381	3,175
Abs. discharge iso-butane, GPM	0.124	0.098	0.085
Abs. discharge iso-butane, gal	569	672	777
Abs. efficiency iso-butane, per cent	64.30	71.78	75.53
Abs. intake N-butane, GPM	0.862	0.862	0.862
Abs. intake N-butane, gal	4,390	6,558	8,745
Abs. discharge N-butane, GPM	0.123	0.088	0.075
Abs. discharge N-butane, gal	565	603	686
Abs. efficiency N-butane, per cent	87.13	90.81	92.16
Abs. intake iso-pentane +, GPM	1.223	1.223	1.223
Abs. intake iso-pentane +, gal	6,229	9,305	12,407
Abs. discharge iso-pentane +, GPM	0.077	0.073	0.088
Abs. discharge iso-pentane +, gal	353	500	804
Abs. efficiency iso-pentane +, per cent	94.33	94.63	93.52

Testing Absorber Efficiency

Tests are often conducted to compare absorber operation without considering the factors that affect the tower operation. The gasoline content of the gas treated will influence the temperature of the tower. The recycled gases in the plant, if any, will change the absorber operation because of more or less heat of absorption. The pressure on the tower also has a bearing on the degree of efficiency particularly in the retrograde region. If any two absorbers are to be compared to determine their relative merits, then the following must be observed: (1) the gas rates through each tower must be the same, (2) the oil rates must be the same, (3) the gas must have the same composition, (4) the pressure on the towers must be the same, (5) the temperatures at the top and base of the absorbers must be the same, (6) the oil composition must be the same, and (7) the same distillation unit must be used in each case. The above precautions should be observed if an accurate comparison is to be made between any two absorbers.

Testing Absorber Efficiency—Laboratory Operation

The actual process of obtaining representative samples and the precautions necessary when checking an absorber operation have been fully covered in previous papers presented before the California Natural Gasoline Association and in the CNGA Bulletin T-5342. Certainly the results of a fractional analysis cannot be better than the sample that was obtained in the plant. Every effort should be made to introduce samples of discharge gases into the fractional analysis column sufficiently large to obtain a good separation between iso-butane, n-butane, and pentanes. Samples of discharge gases less than 50,000 cu centimeters at standard conditions should be avoided. Recent experimental work has proved that sample cylinders heated to 250 F or higher before introducing the sample into the column produce a homogeneous gas containing all of the constituents originally in the gas. Since heating the gas samples to this elevated temperature, all absorber discharge gases tested have shown traces of pentanes and heavier.

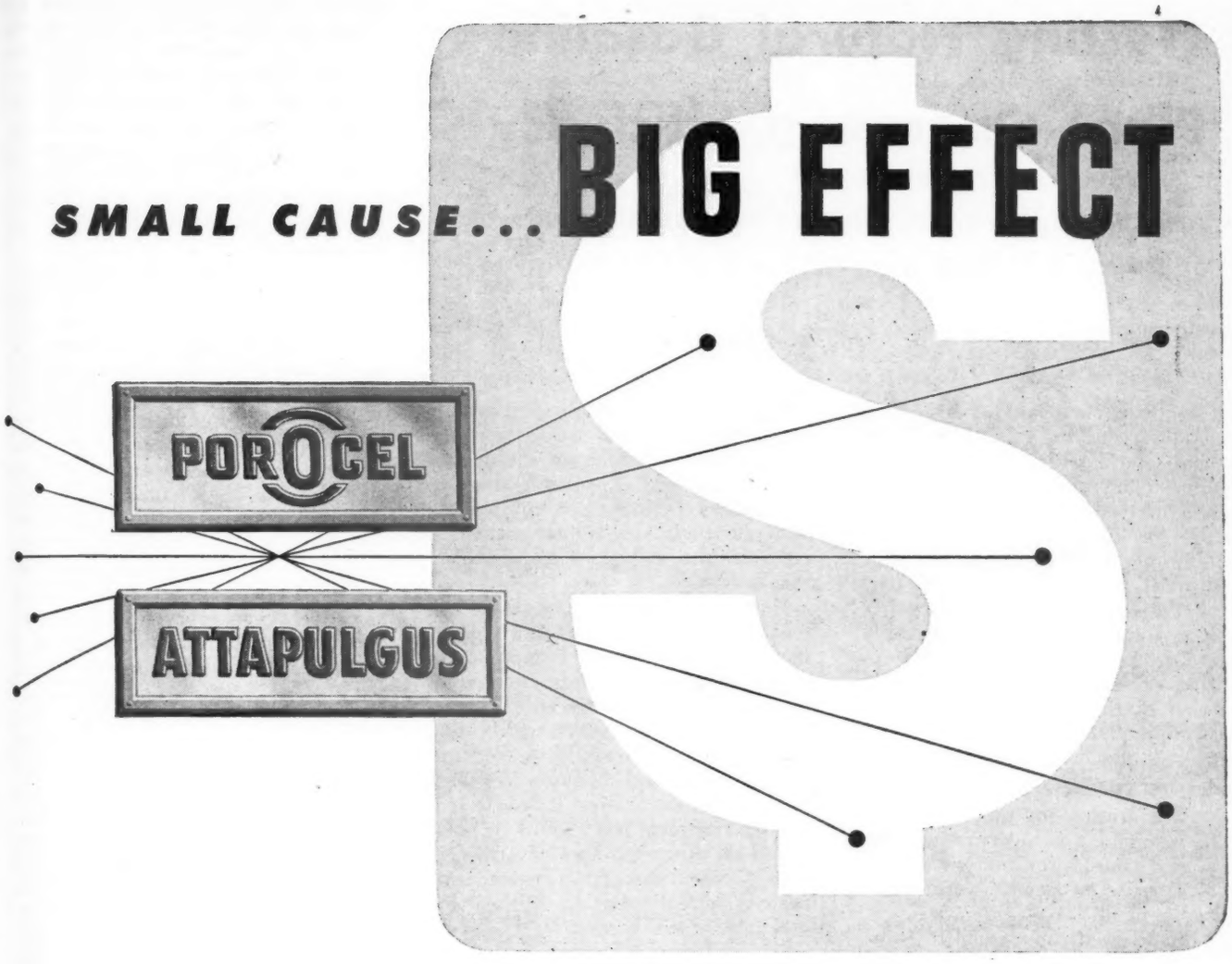
oOo

Average Gas Tax $525. The average car consumes about 8000 gal of gasoline in its lifetime and, at present rates, its owner will pay the state and federal governments about $525 in taxes on that gasoline.

Conclusion

Absorber operation and efficiency are dependent to a large extent upon the operation of the distillation unit of the plant. The absorber can be of the best design obtainable, the lean oil can be in excellent condition, the cooling adequate, but if the distillation system is improperly designed, the gasoline extracted in the absorber will not be retained as a liquid product but will recycle to the absorber. Attention should be given particularly to the old style low pressure plants where a small investment in some type of reabsorber would increase the plant gasoline production as much as 10 per cent. Absorber performance cannot be correctly analyzed without surveying the distillation unit of the plant. * * *

SMALL CAUSE... BIG EFFECT



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Testing Natural Gasoline Plant Operating Efficiency†

Meticulous survey of the conditions and results of operation will show how efficiency can be improved.

J. B. ARMSTRONG*

THIS topic covers an extra large field when discussing the role of the chemist and laboratory in efficient natural gasoline plant operations. Almost all tests employed by the chemist in the natural gasoline industry are tools for determining the operating efficiency of some part of the plant. For the purpose of this forum, however, the paper will be limited to a discussion of a test to determine the overall plant operating efficiency as it applies to extraction of LPG and gasoline in the absorption plant only.

The gasoline plant extraction efficiency test consists of several phases:

1. Preparation for the test.
2. Accumulation of operating data and samples for analysis during a period of steady operation of the plant.
3. Analysis of the results to show the accuracy of the data and reliability of the test. This is accomplished by gas and materials balances and by comparison of the test data with design or previous operating data.
4. Determination of extraction efficiences, product losses, and inefficient and costly operations.
5. Recommendation of corrective measures necessary to obtain more efficient plant operations.

A good plant efficiency test has many important applications. It can be employed as a means of evaluating the operations of a new absorption plant to determine if the plant as a unit will meet the specifications for extraction set forth in the builders contract. It can be utilized as an aid to establish means of increasing efficiency of present plants or to determine the results obtained, after modifications have been made in them. The most important use for the test, however, is as a tool to periodically follow plant operations through years of steady production to eliminate operating inefficiencies and costly maintenance jobs.

†Before California Natural Gasoline Association, 1950.

*Standard Oil Company of California.

Properly conducted, this test can be employed to gage the necessary intervals between maintenance shutdowns and to indicate the probable time of replacement of inefficient equipment. It can be used as an aid for anticipating operating and plant maintenance costs.

Most companies do conduct an efficiency test of some sort at frequent intervals. Usually, these tests are spot checks on plant discharge streams to control absorption losses, or efficiency tests on separate units within the plant; and do not include an accumulation of data and analyses to determine overall efficiencies. It is believed that the complete test should be conducted on every gasoline plant every 12 to 18 months and that sufficient savings can be realized as a result to warrant these periodic tests.

Preparation for the Test

Preliminary work getting ready for a plant test is just as important for a good test as accurate data and analyses taken during the test. Poor and inaccurate data often are a result of poor preparation.

The first step for an overall plant test is to bring the plant flow chart up to date. This chart is a simple schematic flow diagram, which shows the normal flow of materials through the plant. All flow lines; including those that may be used only under abnormal conditions; by pass lines; flow controllers and meters, and all equipment pertinent to the gasoline absorption process are indicated. This is not an elaborate piping drawing, but a schematic layout and should be maintained continually for every gasoline plant. If a flow diagram does not exist, it is recommended that one be drawn up before the plant test is conducted.

The flow chart is checked for correctness by actual inspection of the plant lines and a careful study of the plant cycle is made. Sometimes this may reveal minor changes in the plant, which would effect increased operating efficiency. This is particularly true of plants where incorporation of modern design ideas will increase retention or in plants where many chages have been recently made and the plant cycle is not in the best order. This refers mainly to the disposition of plant vapor and condensate streams. Any obvious improvements within the plant should be recommended and, if possible, these changes should be made before the plant test is conducted.

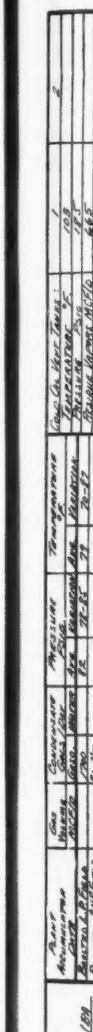
Contact with field personnel: When making plans for a plant test, field personnel should be contacted and notified of your plans. Sometimes it is best to set a date for the test that is mutually agreeable between both plant and field operators. Request the field operators to maintain, as nearly as possible, an average and steady gas load intake to the plant and to notify you of any upset conditions that cannot otherwise be controlled for the period preceding and during the test. The field operators are quite willing to cooperate in every way they can, and this contact normally assures a much better condition for the plant test.

From the flow chart, it is possible to determine what samples and operating data will be taken during the test. At the time the chart is checked for correctness, sampling locations; thermometer wells; pressure gage connections; and metering facilities should be noted. The first time that a test is run or after modification of the plant, there are always additional connections and thermometer wells that will be required during the test. It is best to request installation of these considerably ahead of any test date to give the plant maintenance crew time to get the work done.

Efficiency Test

For an overall plant efficiency test, samples are required for analysis on all plant intakes, products, and discharge streams, including any rectifier residue or plant vapors to the plant fuel system. It is recommended, also, taking samples of any intra-plant streams that may indicate operating efficiency. These normally include absorber intakes, recycle vapor streams, and rectifier reflux streams. In addition, if the efficiency of any individual unit is to be determined concurrently, samples will be required around this unit. All samples are taken in accordance with standard sampling procedure. Analysis of the samples of the products and plant discharge gases are determined by fractional distillation. Analysis of the intakes and other plant streams can be determined by fractional distillation or by the charcoal enrichment test.

On low pressure and vacuum streams, sufficient volume of sample



cannot be obtained in regular sample containers to conduct a charcoal test on a composite 24 hour sample. If these analyses are to be determined by the charcoal method, the tests must be run from spot line samples during the plant test period. In this case, analyses should be taken on the intakes at times of maximum, minimum, and average enrichments, and the average of all three is used for the plant materials balance.

Sample containers should be set in place well ahead of the test. Large LPG cylinders are used for gas samples. Duplicate samples are taken, if possible, to limit the possibility of losing a sample. Cylinders should be steamed and evacuated, then checked for leaks before being used. Cylinders are hooked up to sampling connections with a short header to prevent danger of condensation in the header system. Each header is equipped with a pressure gage for determining cylinder pressures during sampling. The header is flushed out with gas and then left connected to the sample line during the entire test. A shipping tag is attached to each container showing the time of sampling, the cylinder pressure for each increment of sample and other pertinent data regarding the sample. The tag is then initialed after each sample increment is taken.

If possible, the cylinders should be set in a shaded spot to protect from changing atmospheric conditions. The heat from open sun will cause changes in pressure on the sample containers between increments and may result in non-uniform samples being taken.

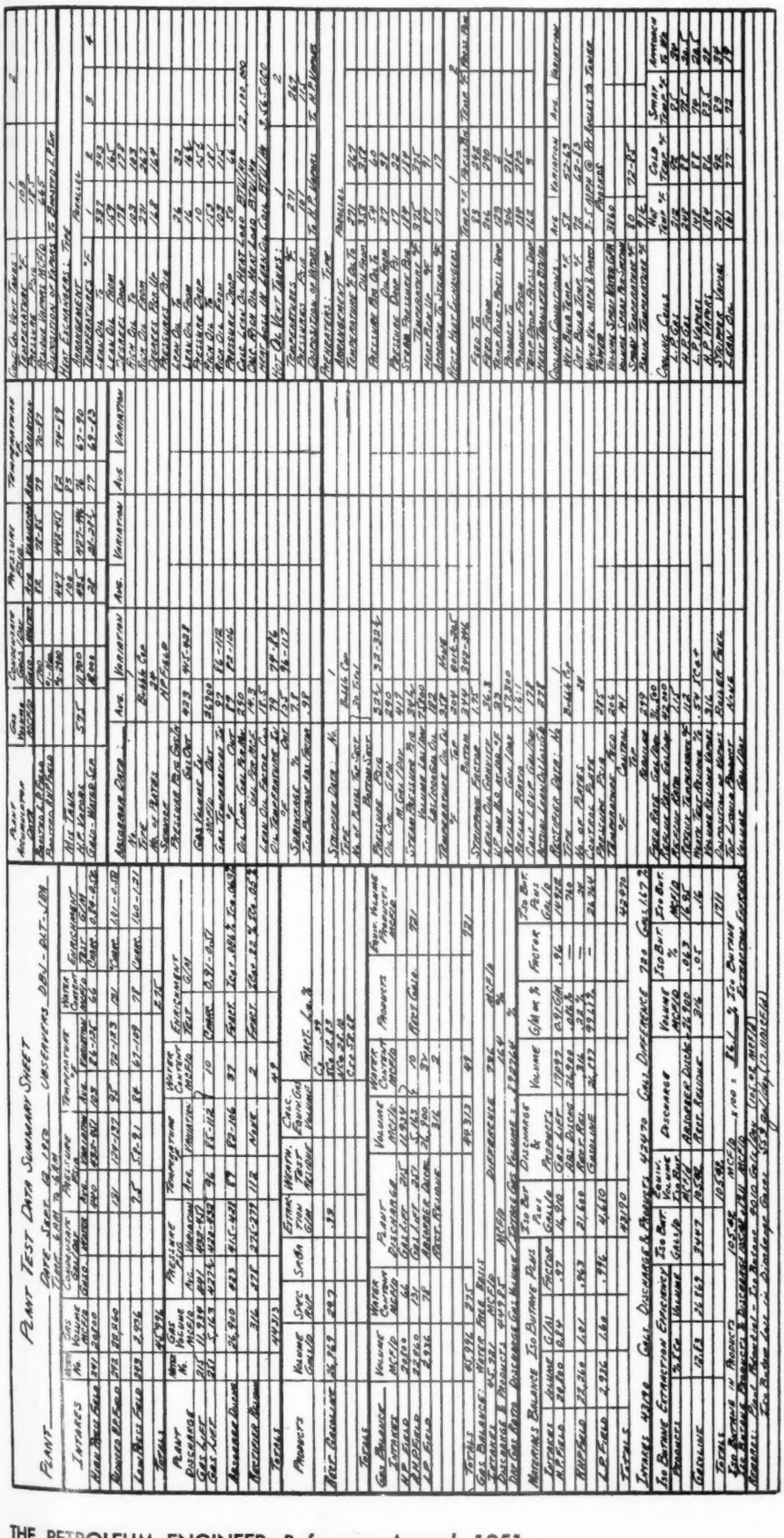
Liquid sample containers are hooked up in the same manner. All liquid samples are taken by water displacement and a measuring cup, to gage the draw off for each sample increment, should be placed with the bomb at each sample point.

Drips that come into the plant with the intakes and are accumulated in the intake scrubbers, or that are collected through a separate gathering system, must be gaged and sampled during the test.

Orifice meters: All orifice meters used for measuring volumes of plant streams must be cleaned, calibrated, and checked prior to the plant test. Static readings on all meters must be checked against a test gage on the line. New gravity and temperature factors are obtained and meter coefficients are recomputed, if necessary, based on the new data. Orifice plates must be checked to see if the size is correct and within the recommended range for accurate readings. If there is any question as to the size and condition of the orifice plates, they should be pulled and inspected. There is a possibility that the plate may be fouled or corroded, or that sand, line scale, or other matter may have accumulated behind the plate, resulting in a wrong reading.

Experience has shown that failure to check meters and plates thoroughly has resulted in some unsatisfactory plant tests. If one reading is incorrect,

Plant test data summary sheet.


PLANT TEST DATA SUMMARY SHEET
PLANT
DATE
INTAKES
Wet Gas
Dry Gas
Low Press Gas
Total
Plant Discharge
Gas Sold
Absorber Room
Recycle Room
Total
Powers
Total
Gas Balance
Compressor Fuel
Vapor Recovery
Total
Gasoline
Total
Gas Balance
Compressor Fuel
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Intakes
To Bare Fractionator Discharge
Powers
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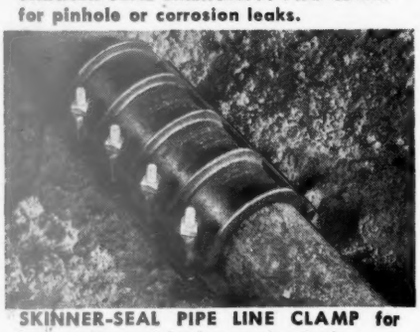

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the plant materials balance will not check and the final results are questionable. Always question any plant measurement before the test and you will be more likely to obtain good test results.

Pressure gages, thermometers, recording and controlling instruments, etc. are all calibrated against standard instruments prior to the test. A separate gage or thermometer should be placed at every location where readings will be taken to avoid moving these instruments during the test. Check that all thermometer wells extend into the flow streams and give accurate readings. Be sure all gage cocks and thermometer wells are not plugged.

All flow controlling equipment must be inspected to see that it is operating properly. By pass valves should be inspected to be sure they are correctly open or closed.

The plant test work sheet: Data readings and samples are taken every four hours during a plant test. For ease and speed in taking the data, a test work sheet is prepared. Each reading, sample, or other item required during the test is listed in the order in which it will be taken on each successive round of the plant. The work sheet is built by making an inspection of the plant, recording each point at which data will be required in the order in which they are reached. There is one column for each round of data. This enables the readings to be taken in the same order each time. It eliminates jumping around on a data sheet, hunting the line on which some reading is to be recorded. It prevents missing data and it makes the readings much quicker and easier to obtain. The time of starting and completing each round of the plant is recorded.

After the preparation for the test is completed, one inspection of the plant is made, taking all data readings and checking sample containers to be sure everything is satisfactory. When making plans for your plant test, schedule your work so that you will have plenty of time both for preparation and during the test to complete everything required. Allow time to take care of unforeseen difficulties. Don't schedule too much work for the day of the test. It is better to get the essential data accurately than to plan too much and not be able to complete it.

Plant Test

Normally, the plant test is conducted over a 24-hour period, from gaging time one morning till the same time the next morning. Shorter tests are not recommended because variations in atmospheric conditions and intake enrichments, which cannot be controlled, might give erroneous results. At the start of the test, gages are taken on all gasoline, LPG, and lean oil storage. If products are shipped by meter, these readings are also taken. Levels in all plant accumulators and surge tanks must be marked. It is recommended that the plant operators be requested to maintain these levels as nearly as possible at the same point during the test. At the end of the test, corrections must be made in the materials balance to account for any change in volumes in the condensates in the plant accumulators.

After the morning gage has been made, the first round of data is taken. When a complete set of data is obtained, the work sheet is studied and any data which appears to be out of line should be rechecked immediately.

During the test, it is necessary to gage the rate of condensate, both gasoline and water, in the various plant accumulators. This normally requires shutting in the vessel and gaging the rise of condensate over a period of time. It is not necessary to gage these accumulators every time data are taken during the test, but it should be done at previously estimated times of maximum, minimum, and average rates.

At the end of the test period, final gages are taken on all storage tanks and accumulators. Any changes in volume of condensate in the plant accumulators must be determined.

Sample containers are disconnected and checked for leaky valves. Analyses are determined as time permits.

All recording charts are accumulated and kept with other plant test data for reference.

The plant test data summary sheet: A summary of all test data is recorded on the data summary sheet, a copy of which is attached. The first section of the sheet summarizes all data necessary to compute the gas and materials balances and the overall isobutane extraction efficiency. Remainder of the sheet summarizes all operating data.

All volumes entered are corrected to 60 F, and where these readings are obtainable from 24-hour recording charts or gages, they are utilized. The average of all readings and the variation in these readings during the test are recorded under operating data.

The plant gas balance can be computed prior to the receipt of sample analyses to indicate the reliability of the test data. This is computed on a water free basis, assuming saturated gas streams at all points. The gas balance compares the total of the plant intake volumes with the sum of the plant discharge gas volumes and the gas equivalent volume of the products. This balance should normally check

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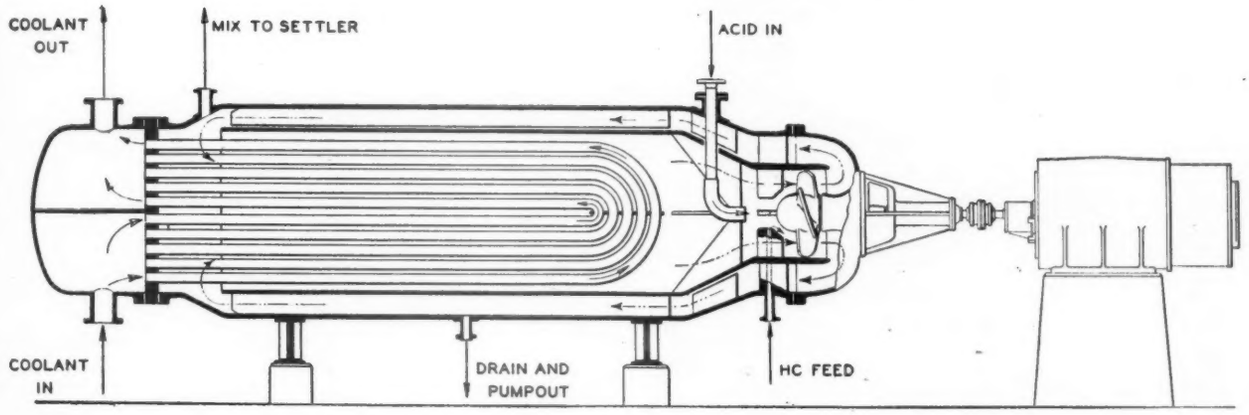

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within three per cent. This deviation is due to inaccuracy of measurements. Any greater deviation indicates erroneous measurements or losses within the plant.

An overall plant materials balance is computed after all sample analyses have been obtained. If fractional analyses have been determined on all samples, this materials balance is made for each component of the gas. If charcoal enrichment tests have been run on the plant intake samples, the balance is computed on the iso-butane plus fraction only. For greater accuracy in this case, a small correction factor is applied to the charcoal test result to indicate iso-butane plus only. The materials balance should check favorably with the preceding gas balance. Any large deviation between the two indicates incorrect analyses or that measurements, particularly of the products, may be in error.

The plant potential and the overall extraction efficiency can now be computed for any component: Propane, iso-butane, or for any desired RVP gasoline. For these calculations, the analyses of the discharge gases and products are used because these data are normally more accurate than the plant intake data. The potential for any component is the total volume of that component available for extraction in the plant. The potential is determined by computing the total volume of the desired component in the discharge gases and the products.

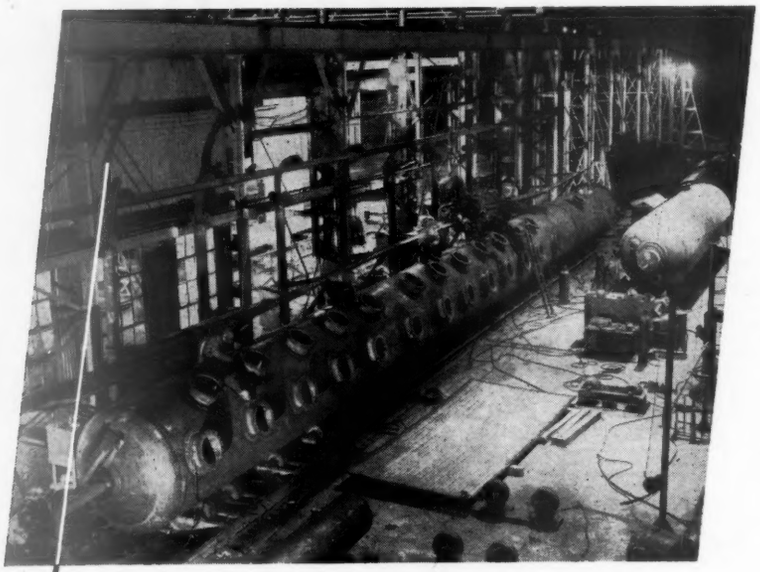
The overall extraction efficiency for any component is then indicated by the ratio of the actual production to the plant potential. This is determined by dividing the volume of the desired component in the products by the total volume of the component in the products and discharge gases.

The attached data sheet shows some of the plant operating data from a recent test. During this test, a gas balance was obtained with a difference between intakes and discharge streams of only 1.64 per cent. The materials balance for iso-butane plus showed a difference of 1.67 per cent. This is an excellent check and indicates that the volumes and analyses, as determined for the test, are accurate. From these data then, an iso-butane potential of 4010 gal per day is shown and an overall iso-butane extraction efficiency of 86.1 per cent for the plant has been determined.

Although the objective of the test is to establish the overall extraction efficiency of the plant, much of the value of a test of this type comes from the plant operating data obtained. After the summary of the data has been completed, readings are compared with previous test data or with design figures. Differences between these figures many point out definite operating inefficiencies, such as costly steam or heat losses, inefficient heat transfers due to fouling, and possible product losses.

Plant cycle calculations supply another means of checking the accuracy of the plant test data. Computation of the flow cycle using intake compositions, and temperature and pressure data obtained during the test should check very closely with determined operating efficiencies and volumes and analyses of the products, discharge gas and recycle vapor streams. These calculations may indicate operating inefficiencies that are not otherwise apparent.

The final phase of the plant test is to make recommendations for changes in the plant, which will correct the operating inefficiencies and/or increase extraction. These changes will vary from minor improvements to large scale plant modifications. The payout of the plant test is obtained when these recommendations are carried out and increased operating efficiencies are realized. These are the savings that will warrant additional plant tests in the future. ★ ★ ★



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THE water being used for cooling today, approaches stupendous figures; it is billions of gallons. How large, we can only estimate. Reports are not accurate on how much water industry uses; we do know, from reports available, that all the water used in the United States approximates 800 gal per day per person. How much of this 800 gal per day can be said to result from use by industry is difficult to estimate. Assuming personal use of 100 gal per day still leaves 700 gal for industry and other purposes. Let us assume half or 400 gal per person per day for industry; on the basis of 150,000,000 people in the United States, that is an estimated requirement of 60,000,000,000 gal per day.

It requires 770 gal of water to process a 42-gal barrel of oil, 3 to 5 gpm per ton of refrigeration, 0.3 to one gallon per horse-power per minute for cooling of cylinders of diesel and gas engines. From steam condensing tables at various cooling water temperatures and varying vacua we can obtain the quantity of water required for this type of cooling. To obtain a 28 in. of vacuum about 100 lb of water must be circulated per pound of steam condensed. Power plants, canneries, chemical plants, etc., use this type of cooling. We know that it requires the cooling of one pound of water through 1 deg to remove 1 Btu of heat. There are many more places where cooling water is used and wasted.

If we knew the total heat that had to be removed in industry, we could then definitely state how nearly correct is our assumed 60,000,000,000 gal of water. These figures, in themselves, seem small, but as a whole, the quantity becomes large. We can therefore state that if only part of the water used for cooling were wasted, the volume would still be too large. The question is "Why waste it?"

There are figures available in the State of California Water Resources Division, which show that half of the water now reaching the Los Angeles City outfall sewer could be saved. A great deal of this water is that which is being used for cooling and then wasted. From a report published in a Los Angeles newspaper, Joseph Jensen, chairman of the board of directors of the Metropolitan Water District, states that each new person arriving in Southern California requires an average of 150 gal per day. In other words, that much additional water must be found. Generally speaking, we normally think only of our own immediate problems, but the problem of water conservation has become one of national importance.

The prime purpose of a piece of cooling equipment is to conserve water. The development of cooling equipment in accomplishing this result will now be presented. The problem of cooling has been one that is always changing. "Why changing?" we may ask. First, and of prime importance, is the quantity and quality of the supply of water. In the early days of this country, conservation of water was of no consequence. Today, this condition has changed, along with many other problems of modern civilization.

It is well, at this time to add other points that have changed the picture of cooling equipment, besides water loss. Frequently, the requirements are colder temperatures of both water and product, better control of temperatures, upkeep and maintenance of the cooling equipment and the correlated equipment (piping, buildings, and vessels). Along with these changes, there have been changes in pumping head and power costs.

Industry, the biggest user of water, is desirous of building their factories near a supply of raw products, and also an abundant supply of water—lake or river. As industry in general, and power companies increased in number, location of plants could not always be adjacent to the source of raw products, water, and labor. As the raw material of one type or another costs considerable to ship, plants were situated with respect to location of raw materials and not water. This change brought about the first use of artificial ponds. In some areas, cooling ponds are still used where temperatures are not very critical.

Spray Ponds for Cooling Water

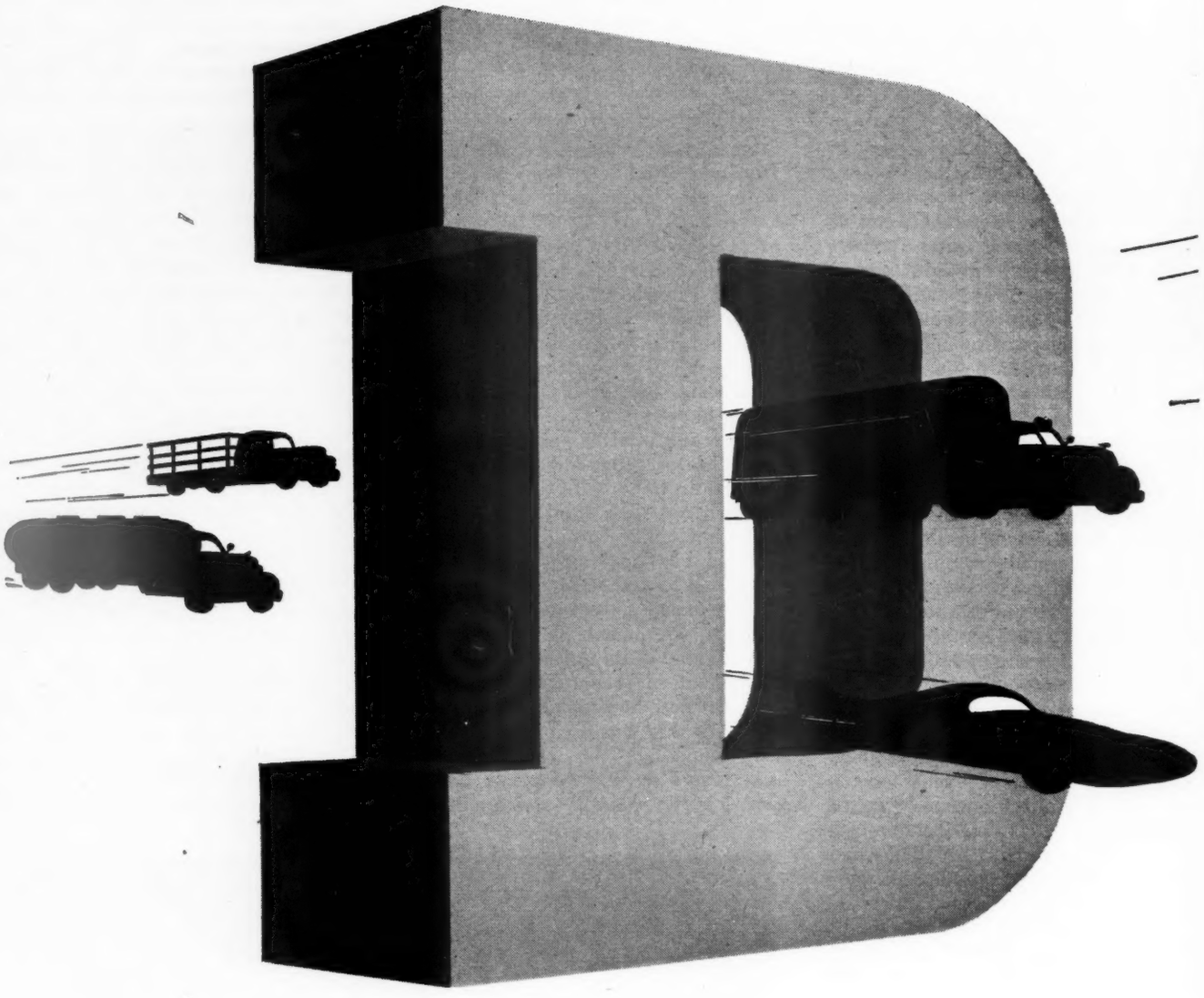
As temperatures became a problem, spray nozzles were developed to aid in cooling of the water in a pond, Fig. 1. This change, in general, reduced the pond size, thus saving in area. Pumping head, however was increased from 6 to 10 psi, above that normally required.

With the development of spray noz-

FIG. 1. Typical spray pond.

†Presented before the California Natural Gasoline Association, Coastal and Taft Chapters.

*The Marley Company.



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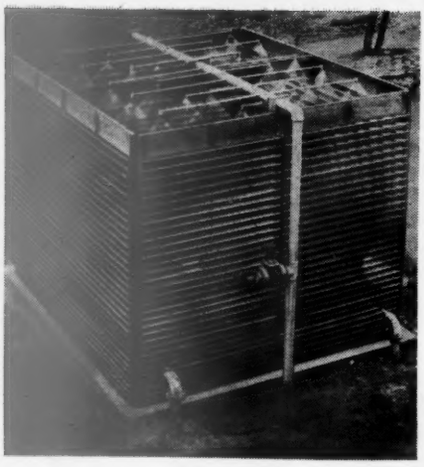

FIG. 2. Small natural-draft cooling tower.

zles, water loss was much greater. This loss changes with the wind; the loss, varying from 8 to 10 per cent. In some locations, plants were actually shut down during high winds, due to excessive water loss. To prevent these excessive losses, solid or louver (wide or narrow) fences were installed. Even with these, water loss was still high, 3 to 8 per cent, the loss varying with the wind.

In general, it can be said that the amount of cooling that could be obtained by the spray pond was in ratio of 1 to 1, or as many degrees could be taken out of the water as the cold water temperature approached the wet bulb, 5 deg approach and 5 deg cooling range. If the ratio was 1 to 2, then double pumping was necessary; 1 to 3, then triple pumping. With larger than 1 to 1 ratio, area of spray ponds had to be increased. With each repumping of the water, the loss due to windage had to be considered. This type of cooling did not give the desired results.

Natural Draft Cooling Towers

With greater temperature differences, and closer approach to the wet bulb, another means was needed to obtain cold water. The natural result was the building of spray walls and the installing of spray nozzles at the top, spraying down, see Fig. 2. To obtain a fair degree of approach to the wet bulb, the nozzles were operated between 30 to 50 psi pressure, in addition to a 20 to 35 ft static pumping head. (Union Oil at Santa Fe Springs and Dominguez have towers of this type.)

What did this do to the pumping head? It increased the head from a few feet, plus line and equipment losses, to the pressures previously mentioned. For discussion, let us assume 1000 gpm circulation, and using an estimate of 0.3 hp per ft per 1000 gpm, the following horsepower would be required: 30 psi = 69.31 ft or 20.8 hp; 50 psi = 115.5 ft or 34.65 hp. What has the cooling equipment manufacturer done about this? The head has been lowered to between 11 and 32 ft of a horsepower of 3.3 and 9.6. Some mnaufacturers go as high as 45 ft or 13.5 hp.

Water loss was also high, not only due to wind, but also due to spray driven out of the tower by the nozzle pressure. Windage and/or nozzle loss, on the average, could be considered as 5 to 10 per cent. This does not seem large, but just consider what it could mean in one year of 365 days. On the basis of 1000 gpm, circulation and water at \$0.0117 per bbl.* (42 gal) with a 10 per cent windage loss. Drift loss = $365 \times 1440 \times 1000 \times 0.10 = 52{,}560{,}000$ gal = 1,251,429 bbl. Cost = $1{,}251{,}429 \times \$0.0117 = \$14{,}641.72$ per year.

What began as a small item has become a large annual expenditure. This is only cost for water loss, not pumping and maintenance cost. When the equipment was installed, water costs were not as high as used in the above example, but there are towers of this type still in existence. The figures used do not include loss due to evaporation, as they would be the same in any type of cooling equipment.

The next development in water cooling was the *deck tower*, see Fig. 3. These towers were of one shape or another, and of various widths and heights. Their prime purpose was to give close approach to the wet bulb and longer cooling range. Their other purpose was to conserve water. Losses in general were reduced under normal operating conditions to about 1 to 3 per cent, with winds not exceeding an average of five miles per hour. This is not always the case, as some plants have shut down from excessive water loss by wind.

Assuming 1000 gpm circulation, from the above example, we find that 1 per cent loss would be 5,256,000 gal per year, for 3 per cent 15,768,150 gal per year; cost would be \$4,392.51 for 3 per cent drift loss. This is an average and could easily vary, yet it is seen that a considerable annual saving has been effected.

With the introduction of the atmospheric tower, less area was required (than with a spray pond) for a given service. Also, only one pumping was needed to obtain the proper cooling. Pumping heads were reduced from 30 to 50 psi spray-filled at the nozzles (exclusive of static head), to no head for open systems, to 6 or 8 psi at the nozzles for pressure system. Static heads, in some cases, were lowered, others increased. Tower heights varied from 8 to 65 ft, an average height of 35 ft. Thus, it can readily be seen that overall pumping head was reduced. This reduction in pumping head reduced operating costs. However, atmospheric towers were not the answer to every problem. Granted, they gave a wider range of cooling and a closer approach to the wet bulb, but under certain conditions, they also increased the saving of water.

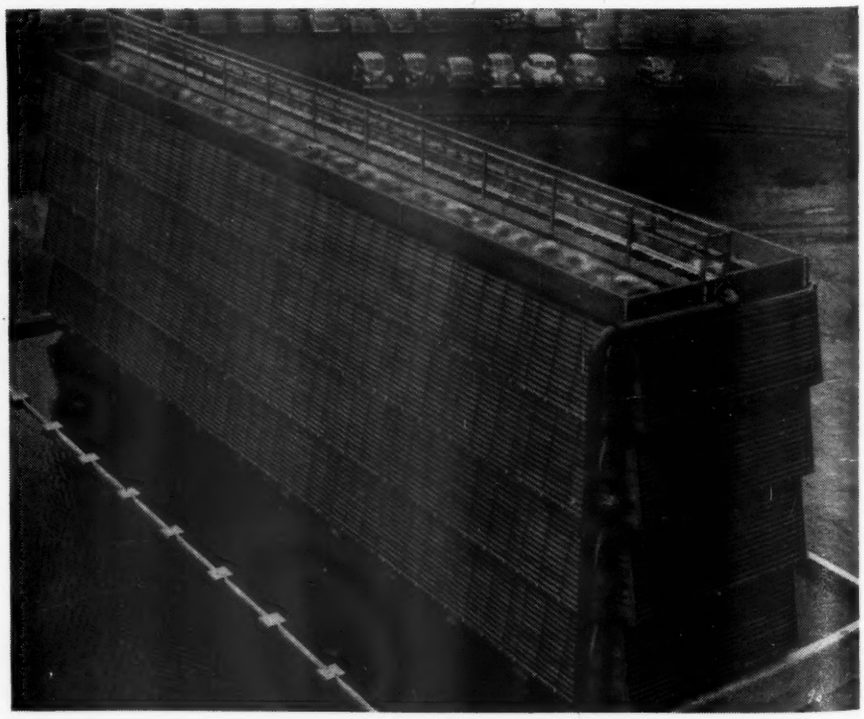

FIG. 3. Atmospheric deck tower.

*The present cost of water, locally in Ventura.

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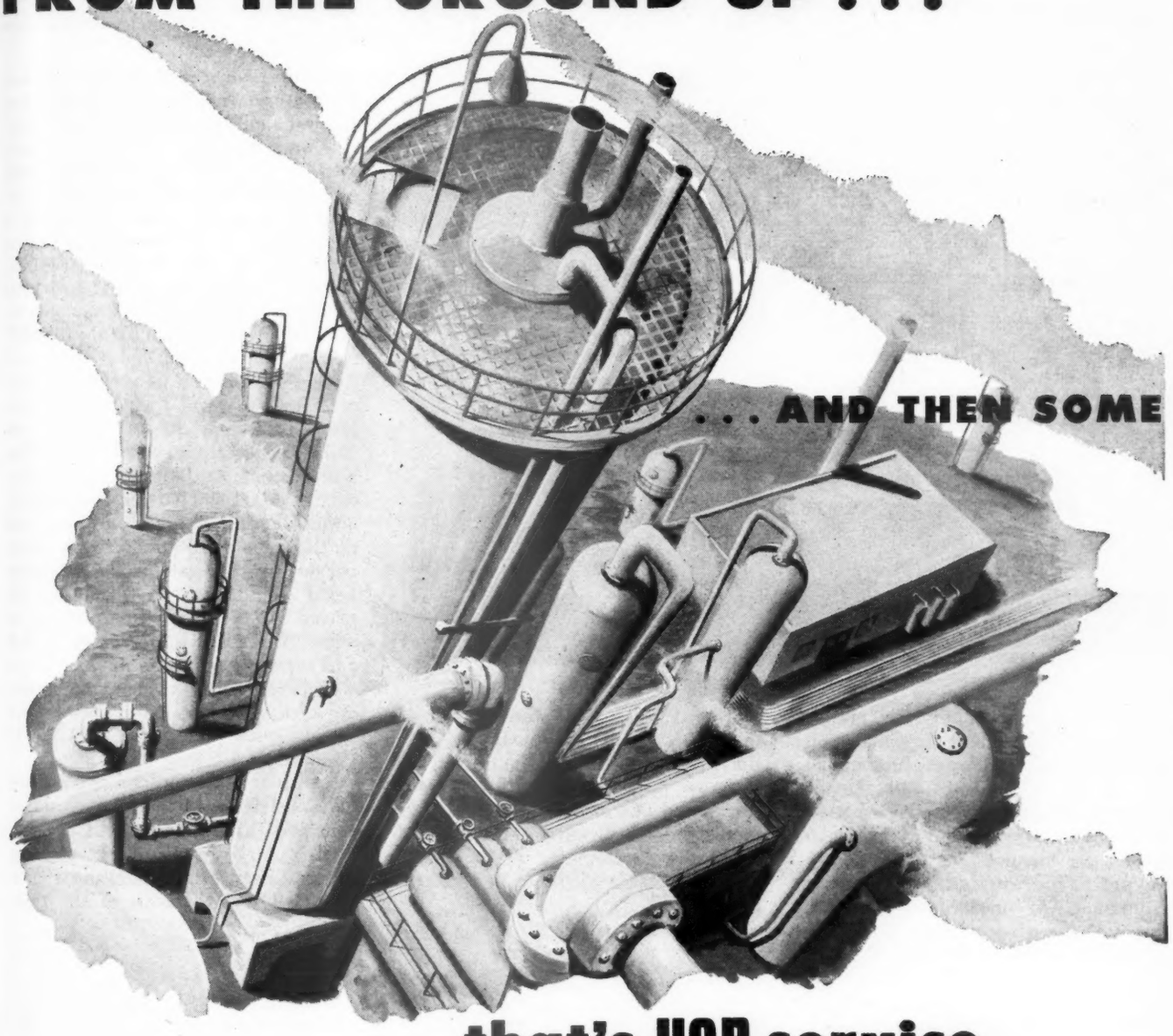

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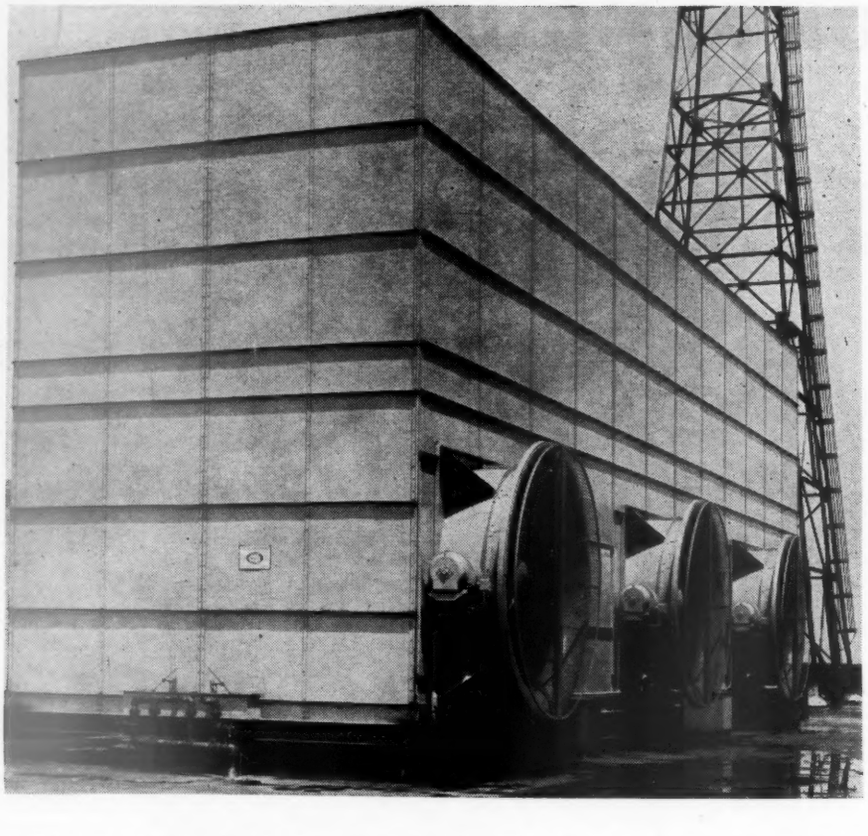


FIG. 4. Forced-draft cooling tower.

The disadvantage of the atmospheric tower is that it depends upon two fickle variables for cooling water: (a) wind, and (b) wet bulb. Means had to be found to overcome the variations of the wind. Wind averages, in most cases, do not give the complete picture. Wind averages are obtained from hourly or quarter-hour readings, therefore the wind velocity is an average for a period of hours. This may give 5 mph, but on further analysis on a time basis, the average would be closer to 2 mph. Based on this difference, a tower built for 2-mph wind would have to be 40 per cent larger than for a 5-mph wind, that is in length for the same tower; height and width could be changed, thus reducing the length.

For very close approach, and for 24 hour operation, towers would necessarily have to be rated on a zero wind. The size, therefore, must be at least double in length that of the 5-mph tower. Even with this length guarantee would not be given for a specific wet bulb temperature.

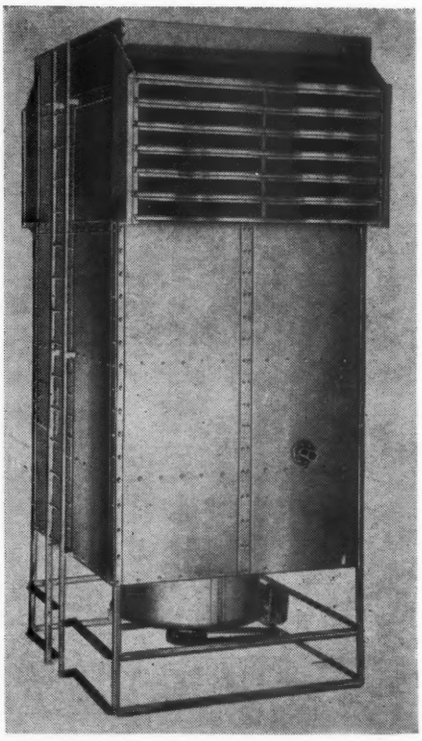
Mechanical Draft Cooling Towers

With the mechanical draft tower a constant air movement would always be obtained with the use of power driven fans. The original designs were of the *forced draft* type. These units employed blower equipment which was available at that time. Blowers were of the squirrel cage type. Mechanical equipment was all situated at the ground in front of the tower, as shown in Fig. 4. Also used were mine-type fans with ability to operate at high static pressures (1 to 10-in. of water). Costs of operating the fans was not considered of much importance. This soon changed, however, and brought about the development of more efficient adjustable pitch propeller type fans.

From the forced draft type of cooling tower (with its many faults) has come the modern induced draft tower, as shown in Figs. 5, 6 and 7. Water (drift) loss for a mechanical draft tower is 0.2 of 1 per cent of that circulated, thus the water loss from a mechanical draft tower circulating 1000 gpm for 365 days a year would be: Drift loss = 365 × 1440 × 1000 × 0.002 = 1,051,200 gal per year = 25,029 bbl. Cost = 25,029 × $0.0117 = $292.84 per year.

On the basis of a water loss of 1 per cent for a natural-draft tower, circulating 1000 gpm, the loss for one year is 5,256,000 gal, against 1,051,200 for a mechanical draft tower, or a difference of 4,204,800 gal per year. That is a considerable amount of water, and on the basis of 150 gallons per capita per day (54,750 gallons per capita per year) would mean 77 people are deprived of their rightful quantity of water. What is actually meant is that a like quantity of water must be found elsewhere. More staggering is the saving of a mechanical draft tower over the old spray pond, ratio of 0.2 to 10 (2 to 100).

There are installations being made in industries, which are only dollar conscious of first cost, and are still buying large atmospheric cooling towers. They are not getting sufficiently cold water much of the time,



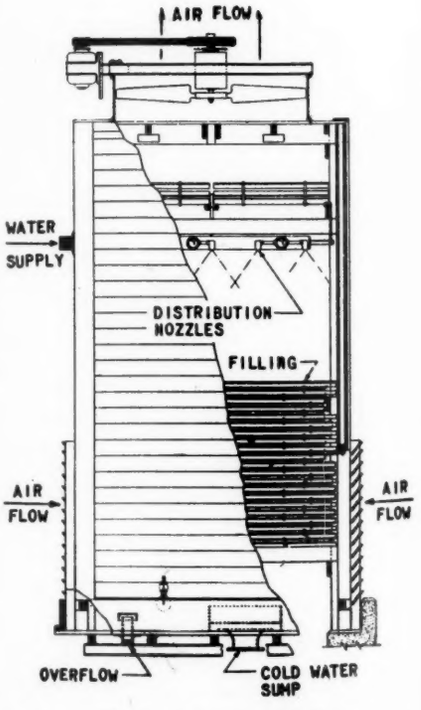


FIG. 5. Induced draft towers are wood or spray filled, or a combination.

Drift Loss with Various Types of Water Cooling Equipment

1000 gpm water circulated — Water cost, $0.28 per 1000 gal

Type of water cooling equipment	Average water loss by drift: Per cent of circulation	Gal per year	Value in dollars	Saving over other types
1. Spray pond or high pressure spray tower	10	52,560,000	$14,641.72	—
2. Natural-draft tower	1	5,256,000	1,464.17	$13,177.25 over spray pond
3. Mechanical draft tower	0.2	1,051,200	292.84	1,171.27 over natural-draft tower

have a high water loss, and require much more ground area for uncertain cooling performance.

When making an evaluation of various types of water-cooling equipment, the effect of the large amount of drift from a natural-draft tower is extremely important, because that much water could do a great deal of damage to surrounding equipment. The water lost from the mechanical draft tower has a much better chance of passing off as evaporated vapor than that from an atmospheric tower, however. Why? Because the vapor from an atmospheric tower is blocked off from a fresh air supply. Mechanical draft towers exhaust directly into a new supply which moves over the fan stack. This advantage, above any other, allows the installation of mechanical draft towers in congested areas.

Dry Air Cooling of Fluids

The water-cooling equipment industry has gone another step further in the development of cooling equipment to conserve water. This step has been the adaptation of radiator-type surfaces to cooling problems. This type of equipment (see Fig. 8) is well adapted for many applications. To list a few: Steam condensing, jacket water cooling, lubrication oil cooling, inter- and after-cooling of gas, overhead vapors (still), superheated ammonia, vegetable oils, absorption oil cooler, quenching oil, soap solutions, and others.

If, in our previous problem, we assume that the temperatures of the final product can be cooled by air, then where is the saving? A listing shows this: No water required, less foundation, no water piping, etc., no water pumps, no water treatment and algae control, smaller equipment (generally less area), no water loss, and no pumping costs. These are tangible and the actual cost can be determined. The intangible items that should be considered are: Maintenance of cooling equipment, maintenance of adjacent equipment, and blow-down of water to prevent excess hardness.

Conclusion

In the development of cooling equipment, we can definitely see that conservation of water supply has always been foremost in the minds of the manufacturer. Along with this de-

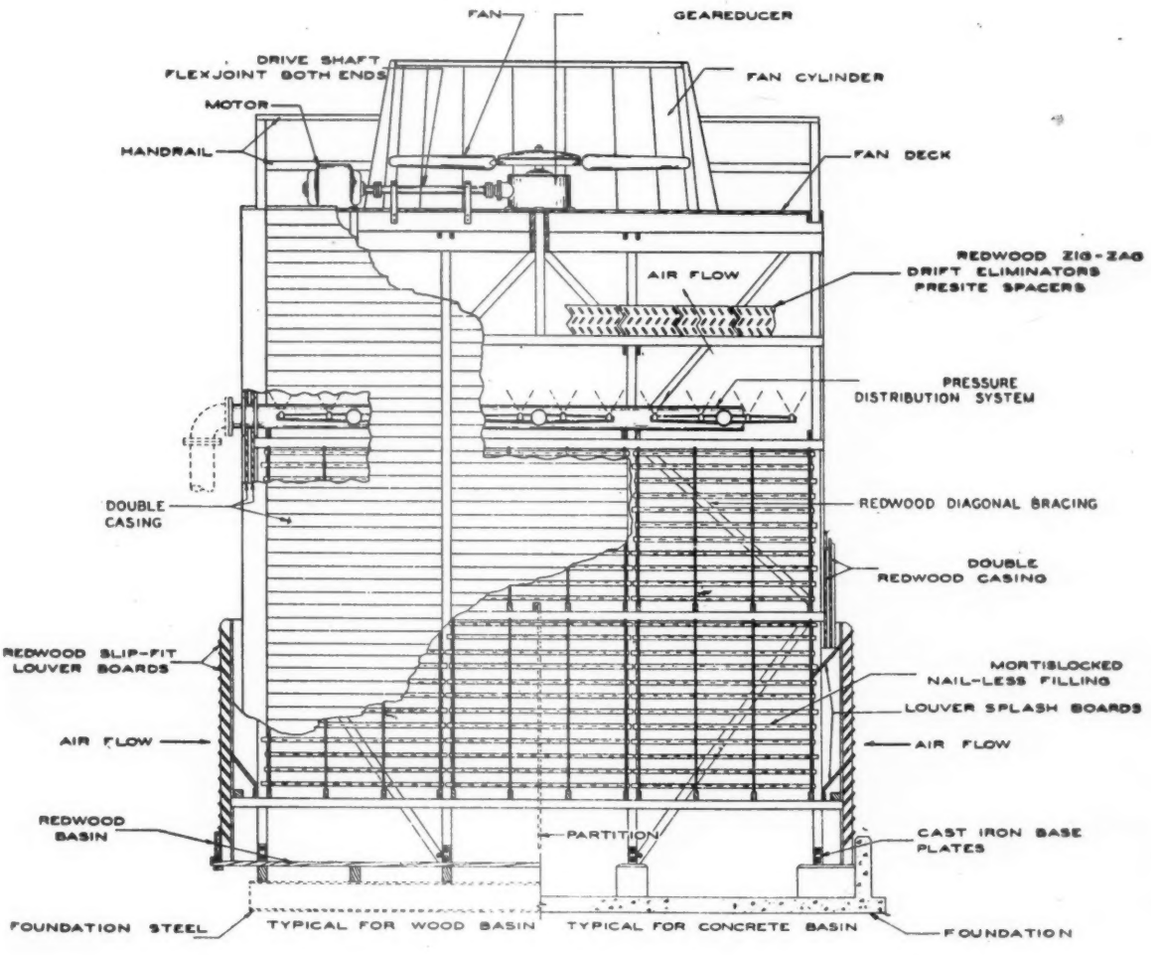


FIG. 6. Section through "conventional" counterflow cooling tower.

velopment has come better equipment.

Consider distributing nozzles. There are many shapes and sizes but one for each type of equipment. Changes are still being made to obtain better break-up of the water.

Very little change has been made except structurally to the deck-type tower, slanting louver type or vertical louver type in the last 15 years. In fact, the wise user of cooling equipment is by-passing this type of tower for the mechanical draft type. Small towers of the spray type are still being used with some refrigeration installations.

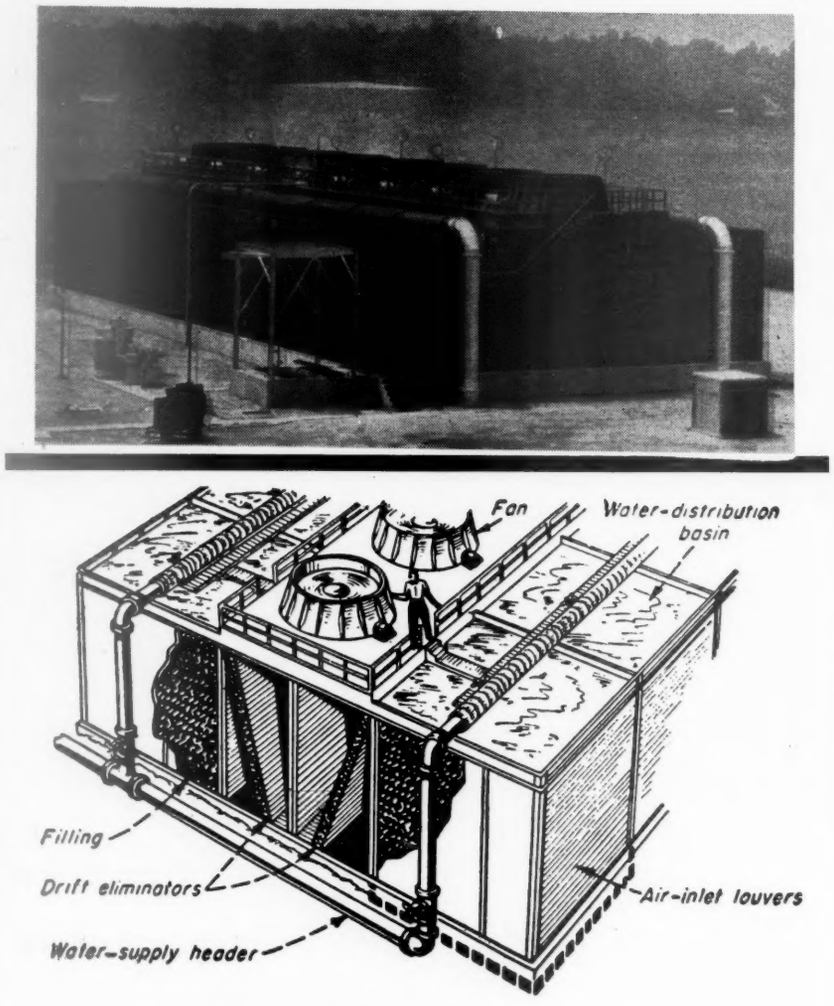


FIG. 7. Large capacity cross-flow, induced-draft towers with open water-distribution system.

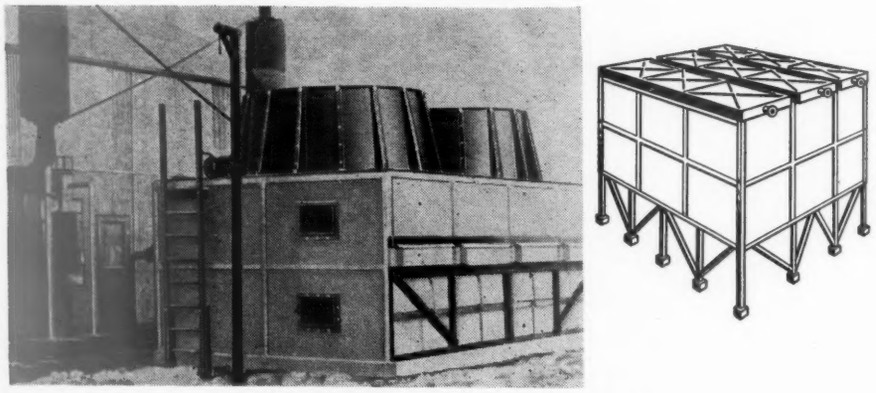


FIG. 8. DriCooler units for cooling fluids; induced draft on left, forced draft on right.

In some cities, Washington, D. C., in particular, no atmospheric tower can be used for air conditioning, only the mechanical draft type. Other cities are requiring the use of a tower on all air conditioning jobs of over 3 tons capacity where water-cooling is required.

The biggest development has been in the mechanical equipment for cooling units. The first towers were supplied with such equipment as blowers, fans, gears, drive shafts, as were available at the time. It was soon found that equipment of this type was not the answer. Why? Primarily, a tower is expected to operate 365 days a year and 24 hr a day. Equipment available for such service was not available for cooling towers built 15 to 20 years ago.

Early tower installations used flat belts and pulleys, then "V" belts with sheaves. Too much maintenance was required to keep equipment in operation continuously, gear motors were tried next. Gear motors did not stand up; to overcome this, special designs were developed with correlated types of gear boxes, fans, and driveshaft units. As a result of these designs, we find that fan sizes have been increased from 8 to 22 ft in diameter. Twelve blades can be compared to the 6 or 8-cylinder gas engine, 3 or 4 blades to the 2 or 4-cylinder engines.

Gear development has produced present-day gear boxes in sizes up to 75 hp. With the development of fans and gears, the improvement of driveshafts has also progressed. The three parts must definitely be coordinated in design and application. Tests have definitely shown that fans must have 6 or more blades to get away from excessive blade vibration.

Some people believe that fans over 168 in. (14 ft) in diameter, are too large; this is erroneous and based on false information. There is in existence today, an aluminum fan, 8 blades, 28 ft in diameter weighing 7000 lb, driven at 375 rpm by a 2000 hp diesel power-plant; tip speed is 33,000 fpm. This fan is situated in the National Advisory Committee for Aeronautics propeller-research wind-tunnel and has been in operation for 23 years, or since 1927. Hence, size is not a governing factor, it is propeller design. Better materials of construction have also been used in mechanical equipment for cooling towers.

It can be definitely concluded that the improvement of design of water-cooling equipment and its wider applications have aided in the conserving of ever-increasing quantities of water. * * *

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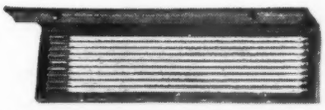

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Chemical Treating Plant for Refinery Waste Water†

H. SCHINDLER

THE petroleum industry has long been aware of its responsibility for proper disposal of its process waste waters; and, long before interest in the abatement of stream pollution became as general as it is now, it had studied and solved its foremost problem, viz., removal of entrained oil from refinery waste waters, and thereby made it possible to eliminate an important source of industrial stream pollution. In particular, the work along this line sponsored by the American Petroleum Institute has been so successful that in many states the authorities in charge of stream-pollution control specify the API separator for the removal of oil from refinery waste water, and do not permit any deviation from this design.

With the greater emphasis on chemical processing in the petroleum industry, the problems of waste-water disposal have changed in character, and special treating methods have had to be devised for those effluents which are not merely suspensions of oil in water, but which contain chemicals in solution. Inasmuch as the manufacture of medicinal and technical white oils, with its attendant production of petroleum sulfonates, is both a petroleum-refining and chemical-processing operation, it appears that the waste-disposal methods of a plant which specializes in these processes should be of interest to the industry as a whole. Such a plant is the Daugherty refinery division of L. Sonneborn Sons, Inc. In this refinery all of those waste waters that contain water-soluble contaminants are treated together, as will be described subsequently in this paper. The waste water that contains only suspended oil is kept completely separate, and is very successfully treated in an API separator.

The Author

Hans Schindler, a native of Vienna, Austria, attended the Institutes of Technology of Munich and Berlin, Germany, as well as the University of Prague, Czechoslovakia, which granted him the degree of doctor of science in 1934. He came to this country in 1938 and joined Pure Oil Company in the research and development laboratories. He was with that company until 1946, except for part of 1945 when he served as a member of the Technical Oil Mission investigating the petroleum and synthetical oil industry in Germany. In 1946 he joined L. Sonnenborn Sons, Inc. at its Daugherty Refinery, Petrolia, Pennsylvania.

Source of Waste Water

The manufacture of white oil consists, in principle, in the exhaustive treatment of suitable petroleum fractions with fuming sulfuric acid, with the result that the finished product is free from colored compounds as well as those able to react with sulfuric acid. The products of the interaction of reactive hydrocarbons with sulfuric acid are alkylated aromatic sulfonates which, depending on their structure, remain dissolved in the oil or which separate from the treated oil, together with polymerized hydrocarbons and spent acid in the form of acid sludge. The oil-soluble sulfonates are recovered from the treated oil, and are purified for sale as a valuable petroleum chemical. The acid-treated oil is finished by neutralization with caustic.

At the Daugherty refinery acid sludge does not represent a source of pollution because the sludge is converted into sulfuric acid and coke. This is accomplished by decomposing the sludge into sulfur dioxide and coke followed by oxidation of sulfur dioxide to sulfuric acid in a conventional contact acid plant. The gas produced in the decomposition step is cooled by direct contact with water, and this cooling water is continuously discharged from the unit. It cannot be directly admitted into the stream because it contains a certain amount of dissolved sulfur dioxide, and has an acidity corresponding to 0.1 to 0.2 per cent sulfuric acid. The volume of this cooling water from the sludge-conversion plant is such that it represents the largest component of the waste waters requiring chemical treatment.

The other source of waste water containing dissolved chemicals is represented by the white-oil plant. Whereas the bulk of the water-soluble sulfonates occurs in the acid sludge and presents no disposal problem, the waste water from the manufacture of white oils and from the recovery and purification of petroleum sulfonates cannot be kept completely free from these compounds because of unavoidable spills and because of the need for periodic cleaning of equipment as well as for operational reasons.

The process waste water, therefore, is colored, acidic, or alkaline, and it contains water-soluble sulfonic acids and sometimes emulsified oil.

Outline of Waste-Water Treating Process

As we have seen, two types of waste water requiring chemical treatment are produced at the Daugherty refinery: 1, water containing sulfur dioxide originating at the sludge-conversion plant; and, 2, acidic or alkaline process waste water containing water-soluble petroleum sulfonates, which originate at the white-oil and petroleum sulfonate plants. After extensive laboratory and pilot-plant work,[1] a procedure was developed which combines the disposal of both wastes in a simple and economical way. The procedure is based on the finding that the process waste water can be decolorized by converting the water-soluble sulfonates into the insoluble calcium salts, and that this reaction can only be successfully completed if the free sulfonic acids, rather than the corresponding salts, are reacted with lime. On this basis the following method was found most advantageous, because it combines the chemical requirements of the process-water disposal with the purification of the sludge-conversion plant waste water:

1. Adjustment of process waste to a pH of 5 by mixing with acidic water from sludge-conversion plant.
2. Precipitation of sulfonic acids and mineral acid with hydrated lime at a pH of 7.0 to 8.4.
3. Continuous settling of precipitate and discharge of treated water.

The small-scale results with this procedure were so encouraging that it was decided to use it full-scale, and a complete plant was designed by Morris Knowles, Inc., Pittsburgh, under the direction of Edward F. Twomey of that firm. The heavy construction work, including all concrete work, was carried out by a contractor, and the equipment was installed by the refinery staff.

†Presented to a session on refinery waste water during the 16th mid-year meeting of the American Petroleum Institute's Division of Refining, Tulsa, Oklahoma, May 1, 1951.

[1] H. Schindler, Petroleum Refiner 28 [10] (153) 1949.

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Waste-Water Collecting System and Treating Plant

Waste water originating in the white-oil manufacturing process is conducted through tile sewers which have been made tight with acid-proof cement, to a concrete sump of about 3,750-gal capacity, from where it is pumped through a 4-in. line to a 50,000-gal waste-water holding tank located near the treating plant. The sump is equipped with a vertical centrifugal-type bronze-fitted sump pump, with a capacity of 200 gal per min and, for emergencies, a steam pump of about the same capacity. The waste water from the purification of petroleum sulfonates is collected in a sump which holds about 2000 gal, and is pumped into the same waste-water holding tank as the white-oil process waste water. The same line is also used for both waste waters. The volume of the combined waste amounts to an average of 50,000 gal per day. Originally, Transite pipe was used for handling the process waste water because steel had been found unsuitable in a temporary waste-water treating installation. Inspection of the Transite pipe after only a few months' service, however, indicated severe corrosion; therefore, use of this construction material for the type of process waste water encountered at the Daugherty refinery cannot be continued. The unpredictable change of alkalinity, acidity, oil content, salt concentration, etc. — aggravated by occasional elevated temperatures and the presence of abrasive material, such as clay — makes selection of an adequate piping material very difficult. Bronze has given stisfactory service in pumps and valves.

Although it is attempted to collect process waste water at its source and thereby keep to a minimum the volume of water requiring chemical treatment, it is not possible to eliminate completely spills or to avoid contact of storm water with areas impregnated with sludge and similar wastes. For this reason a certain amount of storm water had to be included in the waste-water collecting system. This water is collected in a sump equipped with 2 vertical centrifugal sewage pumps, with a capacity of 1,400 gal per min each, and is pumped through a 16-in. standard cast-iron line to a holding basin with a capacity of about 550,000 gal. The accumulated storm water is treated together with the other waste waters.

The acidic waste water from the sludge-conversion plant — which amounts to 180,000 gal per day of acidic water with a temperature of 180 F—is run by gravity through a 4-in. rubber-lined steel pipe directly to the treating plant. In this way all unnecessary handling of this very corrosive water is avoided. The properties of the waste waters and their volume are summarized in Table 1.

TABLE 1. Properties and volume of waste-water.

Source of waste water	Temperature (Deg F)	Properties	Volume (gallons per day)	Feed rate to treating plant (gallons er minute)
Process water from white-oil and petroleum-sulfonate plant	60 to 150	Alkaline or acidic; contains salts, water-soluble sulfonates, and emulsified oil	18,000 to 40,000	35
Water from direct cooling of gases from sludge-conversion plant	180	Acidic (dissolved sulfur dioxide equivalent to 0.1 to 0.2 per cent sulfuric acid)	180,000	125
Storm water	60 to 80	Slightly acidic	.....	40 (maximum)

As pointed out previously herein, treatment of the waste water consists in mixing the acidic waste water with the process waste water containing water-soluble sulfonates so that these are converted into the sulfonic acids in case the process water is alkaline. The acidic mixture is then treated with lime. A flow diagram for the process is given in Fig. 1.

Mixing of the waste waters is carried out in a square concrete tank, 5 ft square and 4 ft deep, which is lined with acid-resistant brick. The acidic mixture continuously overflows into an identical concrete tank, where it is mixed with hydrated lime suspended in a small amount of carrier water. The retention time in each of the tanks is 8 min. Agitation is provided by mixers manufactured by Walker Process Equipment, Inc. The speed of the stirrer in the mixing tank is 600 rpm, whereas that of the stirrer in the neutralizing tank is 300 rpm.

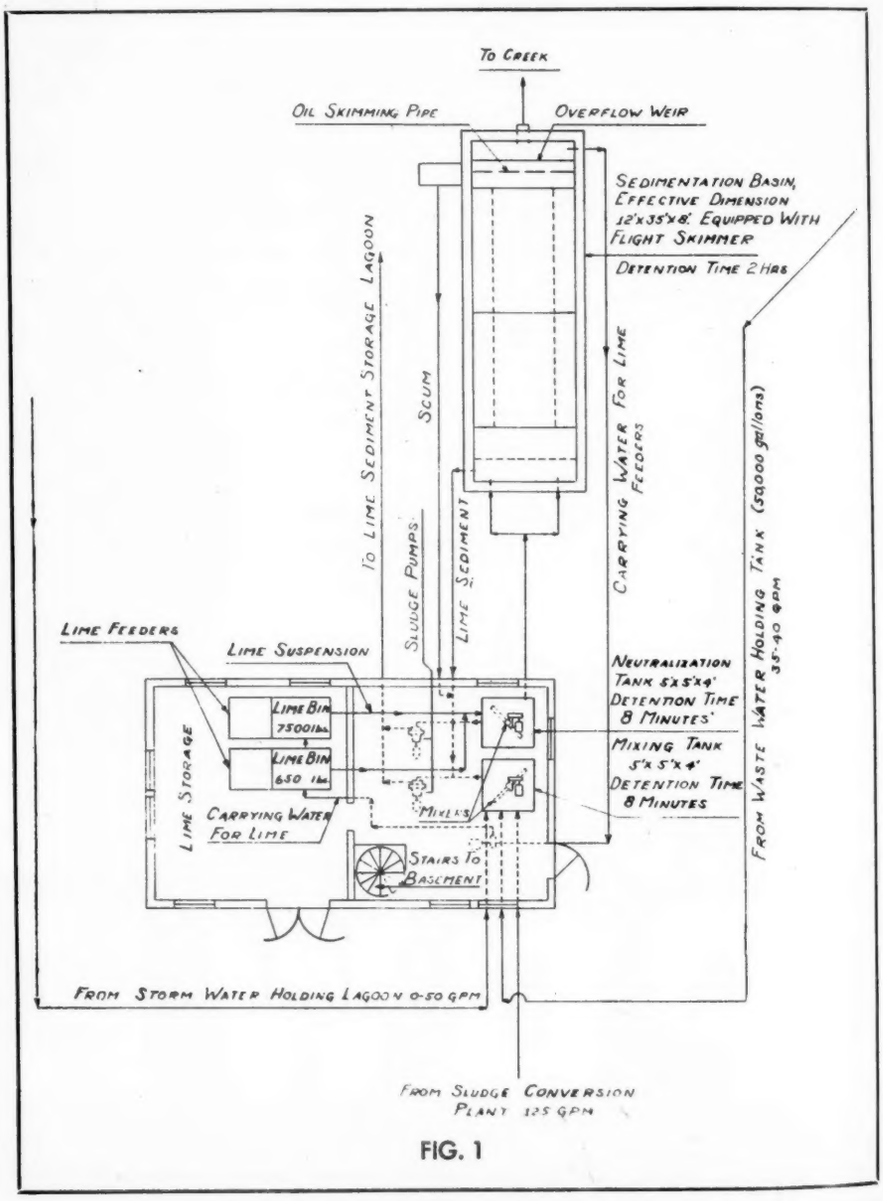
To Creek
Oil Skimming Pipe
Overflow Weir
Sedimentation Basin, Effective Dimension 12'x35'x8'. Equipped With Flight Skimmer
Detention Time 2 Hrs
To Lime Sediment Storage Lagoon
Scum
Sludge Pumps
Lime Sediment
Carrying Water For Lime Feeders
From Waste Water Holding Tank (39000 gallons) 35-40 GPM
Lime Feeders
Lime Suspension
Neutralization Tank 5'x5'x4' Detention Time 8 Minutes
Mixing Tank 5'x5'x4' Detention Time 8 Minutes
Lime Bin 7500 lbs.
Lime Bin 650 lbs.
Lime Storage
Carrying Water For Lime
Mixers
Stairs To Basement
From Storm Water Holding Lagoon 0-50 GPM
From Sludge Conversion Plant 125 GPM

FIG. 1

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This national phenomenon is a tribute to the productive and selling genius of the American soap industry. Mathieson is proud to be a supplier of caustic soda and other materials needed in the manufacture of soap and soap products.

The large-scale ability to supply industry with such essential raw materials is a result of Mathieson's constant research in the manufacture of basic heavy chemicals and their many specialized derivatives. And Mathieson service is marked by *dependability,* too—through ample capacity, wide diversity, and constant flexibility.

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TABLE 2. Operating data of waste-water treating plant.

Month	Process waste water: Frequency of acidic reaction (days)	Process waste water: Average acidity (PPM of sulfuric acid)	Process waste water: Frequency of alkaline reaction (days)	Process waste water: Alkalinity (PPM of sodium hydroxide)	Process waste water: Composite sample: Color (PPM)	Process waste water: Composite sample: Oxygen consumed (PPM)	Water treated: Process waste water (gallons)	Water treated: Total waste water (gallons)	Acidity of mixed waste water (PPM of sulfuric acid)	Lime used (tons)	pH	Properties of effluent: Color (PPM)	Properties of effluent: Oxygen consumed (PPM)
June, 1950	16	983	14	1,950	1,700	518	1,678,264	7,413,264	1,360	55.3	7.5	30	42
July, 1950	16	2,180	15	1,275	5,100	760	1,718,496	7,551,496	1,660	54.1	7.0	45	50
August, 1950	19	785	12	440	2,150	460	1,505,796	7,305,796	1,325	50.4	7.0	45	37
September, 1950	23	1,365	7	314	5,000	545	1,396,400	7,115,384	1,435	54.7	7.0	60	35
October, 1950	17	674	14	515	3,160	535	1,387,540	7,027,540	1,330	52.3	7.0	65	40
November, 1950	16	586	14	1,010	2,600	623	1,380,040	7,220,040	1,150	44.5	7.0	50	40

The treating tanks are covered; and a fume duct, made of 6-in. spiral pipe, has been found adequate for the removal of sulfur-dioxide fumes. This simple arrangement has completely eliminated any fume nuisance in the treating building.

Regulation of the treating operation is twofold: 1, control of the volume of process waste and storm water added to the constant flow of acidic waste water; and, 2, control of the amount of lime added. The flow rate of the process waste water from the holding tank to the treating plant is regulated by means of an automatic float valve which is operated in conjunction with an indicating flow meter. The flow of storm water from the basin is controlled manually.

Hydrated lime is applied to the acidic waste water by means of two automatic lime feeders. Only one of the feeders is normally operated; the second one serves as a standby.

In order to conserve water, treated effluent is used as carrier water for the lime feeders. The water is pumped to the lime feeders with a 15-gal-per-min bronze turbine-type pump, and its temperature is maintained at 80 F by mixing with a small amount of well water through a thermostatically controlled valve. Control of the carrier-water temperature avoids any difficulty with feeding damp lime, which occurs when the effluent is hot.

Hydrated lime is received in 50-lb bags, and is stored in the room which contains the feeders.

The treated water continuously overflows into a rectangular settling basin (effective dimensions: 12 ft by 35 ft by 8 ft), equipped with a sludge collector of the flight skimmer type. The retention time in the settling basin at the design flow of 200 gal per min is 2 hours. Scum and oil that collect on the surface are removed by a hand-operated skimmer pipe, which conducts the scum and oil to a collecting pit. The lime sediment and the oil and scum are pumped to a lagoon by means of a 50-gal-per-min centrifugal sludge pump situated in the basement of the building that houses the treating equipment. A second identical pump serves as a standby. Free water collects on the surface of the lime-sediment lagoon and overflows into the storm-water basin, from where it is returned to the treating plant.

The entire mechanical equipment for the treating plant was made by Walker Process Equipment, Inc.

Lime sludge stored in a lagoon is periodically pumped into a truck designed for the purpose, and is dumped into a sealed, abandoned shaft mine for ultimate disposal.

Treating Plant Operation and Results

The waste-water treating plant was begun in February 1950, and has operated satisfactorily from the beginning. The operating data given in Table 2 cover 6 representative months.

Because of the fluctuation in the properties of the process waste water, the periods during which it was alkaline or acidic, as well as the periods of concentration of acid and alkali, have been listed separately in Table 2. This should give a somewhat better picture of the operations than a single figure for the average reaction of a composite monthly sample, inasmuch as the waste water is usually uniform during each 24-hour period.

On the other hand, color and oxygen consumed, to a certain extent, are independent of the reaction of the water and, consequently, in this case the information provided by a composite sample should be adequate.

It will be noted that the lime consumption does not run parallel with the acidity of the mixed waste waters. The reason for this is that lime consumption, to a considerable extent, is dependent on the sulfonate concentration; i.e., the color of the waste water and the need for lime for precipitating the sulfonates and for reducing the color are indicated by the correlation of color of the process waste water and lime consumption. In all cases the color reduction is not less than 98 per cent.

Usually, addition of an amount of lime to give a pH of 7 in the neutralizing tank is sufficient to obtain a lime precipitate that will settle rapidly. In some cases, however, especially at high concentrations of sulfonates in the water—it is necessary to raise the pH to 8.4. An excess of lime above that required for neutralization is also useful in case of a large amount of emulsified oil, inasmuch as the heavier precipitate adsorbs the oil.

The fact that the waste-water properties are usually uniform for about 24 hours makes it possible to operate the plant with only one full-time operator, for the reason that the control setting made at the end of the day shift usually needs only minor adjustments during the following 16 hours. These adjustments are made by the operators of another plant unit nearby, who provide part-time supervision during the period when no operator is on duty in the treating plant.

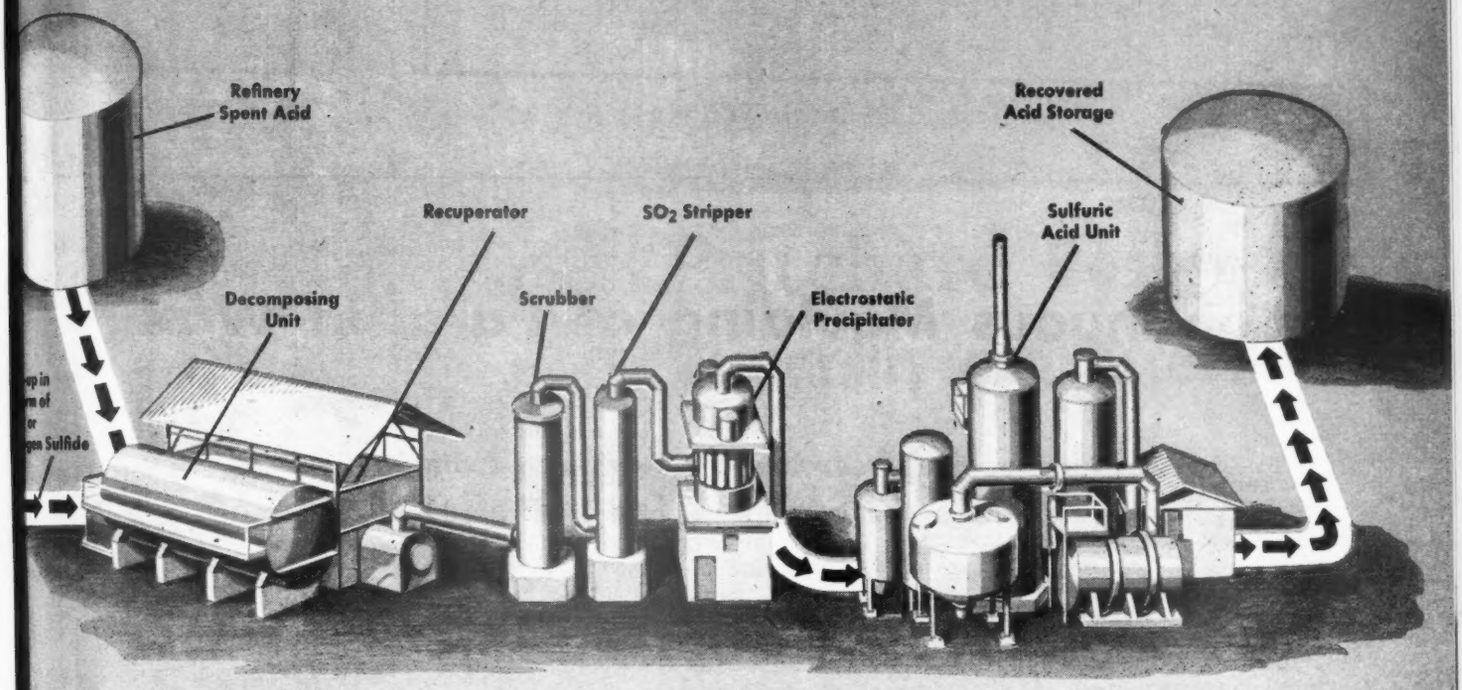
In order to make this operating schedule possible, it was necessary to increase the hopper capacity to 7500 lb of one of the lime feeders from the original capacity of 650 lb. With the increased hopper capacity, the full-time operator can fill the lime feeder and make the necessary settings so that the part-time operators only need to check the effluent quality and make minor changes in the lime-feed rate. The extension of the hopper was carried out by the refinery staff.

No unusual operating difficulties have been encountered thus far. As is usual for a system that handles lime or a lime precipitate in suspension, it is necessary periodically to clean the lines that carry these suspensions, but the operators have found that this can be accomplished easily by steam (if necessary, under pressure) instead of by rodding.

It should be noted that the volume of waste water listed as "plant throughput" in Table 2 does not include any dilution by storm water except for the November data, inasmuch as the storm-water pumping station was only completed in the last part of October 1950. However, the data do include an average of 282,000 gal per month of storm-water runoff from an abandoned acid-sludge pond. Addition of the regular plant storm water —because of its low concentration of sulfonates, acid, caustic, and similar —somewhat improves operations because this additional water acts as a diluent for the much more highly contaminated process water. * * *

CHEMICO OFFERS AN ECONOMICAL PROCESS FOR

Spent Alkylation Acid Regeneration



*D*ue to the increased cost of brimstone and the vital need to conserve basic sulfur deposits, petroleum refiners producing high octane aviation gasoline will find it desirable to recover the sulfuric acid from their spent alkylation acid. For this purpose, Chemico offers a proven and economical process.

In this process, spent alkylation acid—now in greater supply as a result of the increased manufacture of high octane gasoline—is sprayed into a furnace maintained at a high heat with auxiliary burners. Sulfur or hydrogen sulfide may be used as fuel thereby producing SO_2 gas for the production of make-up acid.

A limited amount of other liquid acid sludges, high in hydrocarbon content, may also be added to the alkylation spent acid, thus providing fuel as well as additional acid production. The hydrocarbons are completely consumed and the acid is broken down into its components—sulfur dioxide, oxygen and water. After the water is removed, the gas is processed to fresh acid of 98% strength in a Chemico contact sulfuric acid unit. Send for additional information, stating your requirements.

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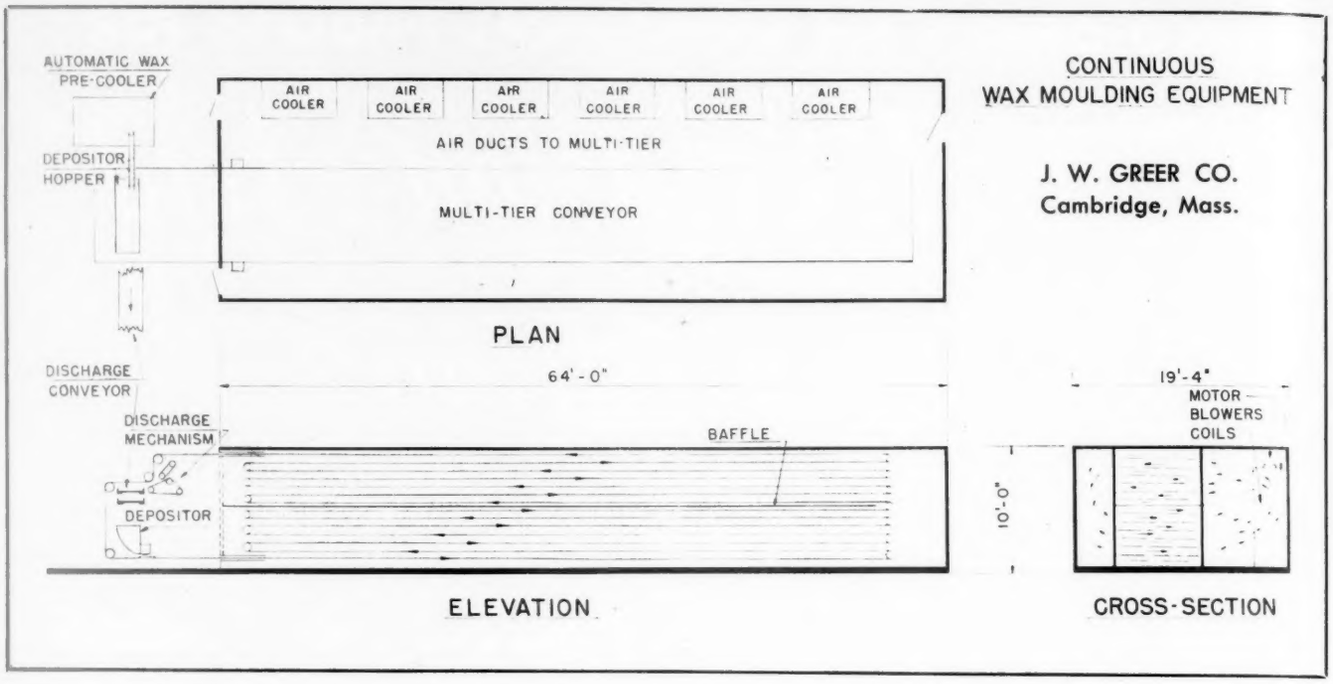
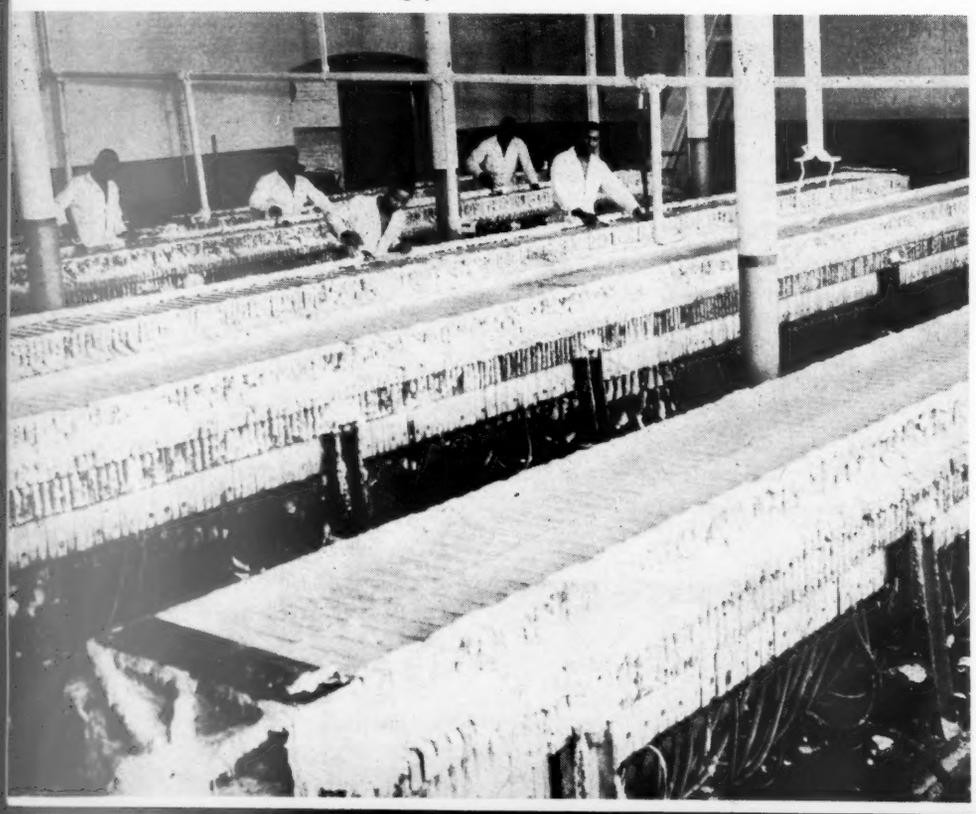


Continuous Moulding of Paraffin Wax†

New development freezes and moulds in a continuous process — will improve the economics and technology of this field

L. H. JENNINGS,* J. H. BEARD,* and V. A. KALICHEVSKY*

Conventional batch moulding process.

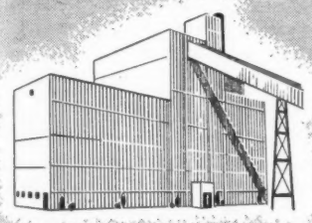


FOR many years paraffin wax was regarded as a surplus product of little value to refineries and was normally disposed of as a cracking stock. Only a small portion of the mineral waxes, necessarily manufactured in the normal refining processes for gasolines and oils, ever found commercial outlets, and what little wax was sold was utilized mainly as an adulterant or as a cheap substitute for vegetable and animal waxes.

Today, however, continuously advancing knowledge of the nature of mineral waxes and modern wax manufacturing techniques have resulted in a tremendously increased popularity for products made from petroleum wax. Then too, petroleum waxes have won new outlets on their own merits and the wax industry as a whole has acquired a present important position in industrial and home life.

†Presented before technical meeting of the Western Petroleum Refiners Association, Wichita, Kansas, July 20, 1951.

*Refining division, Magnolia Petroleum Company.



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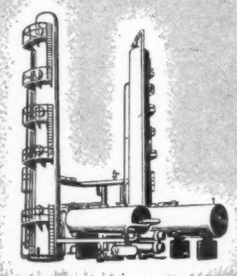

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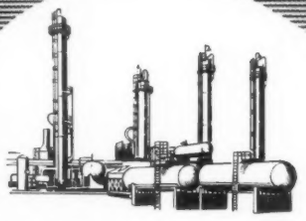

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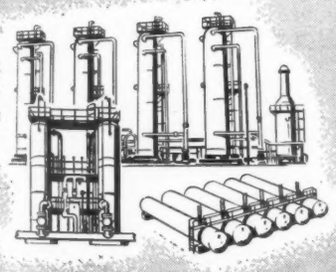

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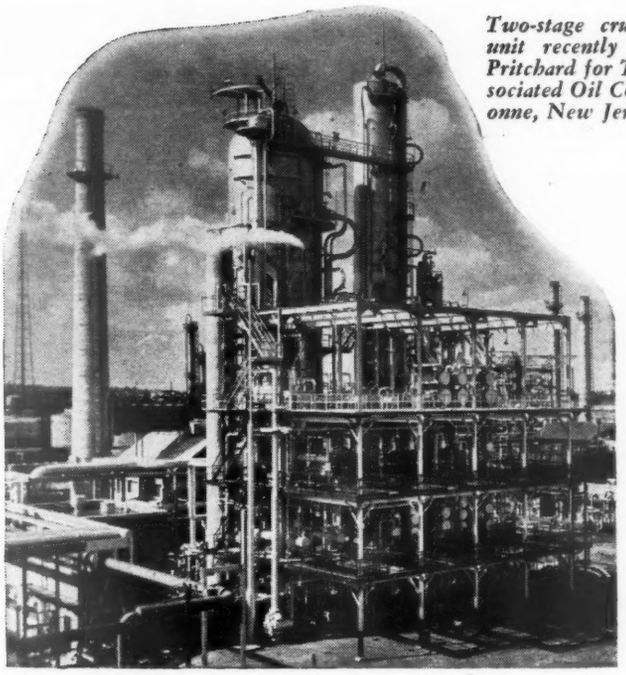

Two-stage crude distillation unit recently completed by Pritchard for Tide Water Associated Oil Company at Bayonne, New Jersey.

Pritchard Designs for Versatility and Accessibility

This unit is typical of Pritchard's forward looking ingenuity in Design, Engineering and Construction. Designed to the customer's requirements for replacement of an existing crude unit and for processing six different types of crude oil at a nominal capacity of 22,500 bbls. day, this unit simultaneously produces eight different distillate fractions ranging from light gasoline to cylinder stock!

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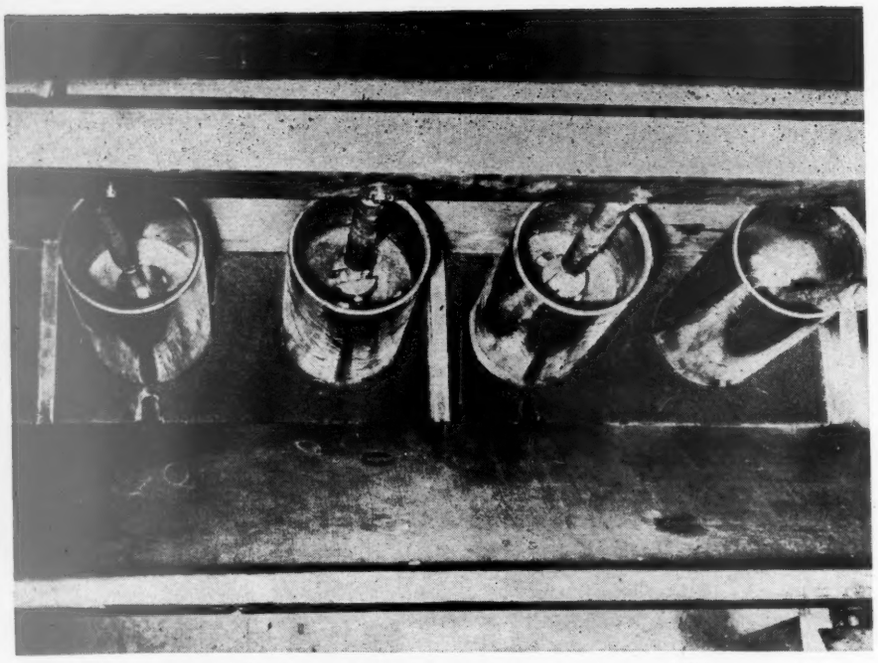


Positive displacement pistons discharge wax into cooling pans.

The rapid growth of the industry may be visualized from the fact that the total quantity of petroleum waxes that will be produced in this country in 1951 will easily pass the one billion pound mark, and represents an increase of some 30 or 40 per cent over the last decade. Considerably more than one-half of this figure will be represented by paraffin waxes of various melting points. Close to three-fourths of these waxes will be consumed for processing paper, while the rest will be utilized in candle and electrical insulation manufacture, in the textile, leather, cosmetic, and lumber industries and in the formulation of polishes. These varied uses also explain the necessity of supplying a widening market with more than one grade of wax.

Paraffin wax is usually sold by refineries in the form of cakes, which vary in size, depending upon the available moulding equipment and the wishes of customers. These cakes are frequently referred to as slabs of wax.

While wax processing methods have steadily improved, wax moulding techniques have remained practically unchanged from the batch moulding method first used by the industry. Conventional equipment is still represented by a modified plate and frame process with moulds and cooling plate substituted for rings and filter plates.

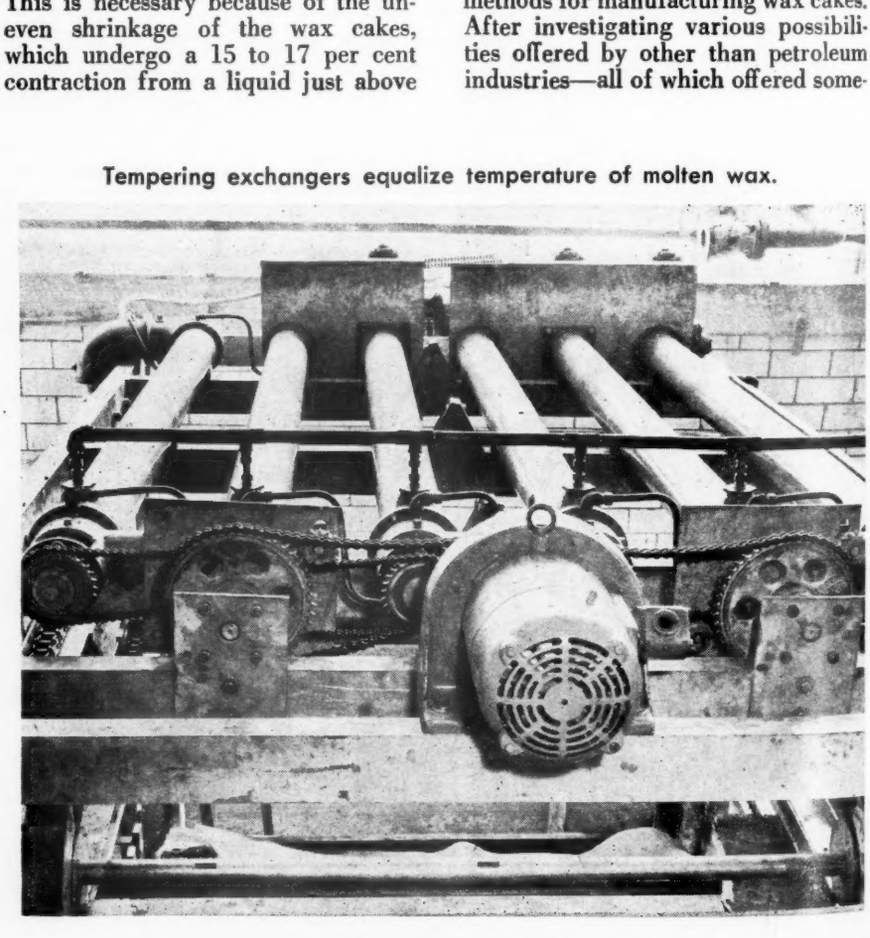
In this batch method the sides of the moulds and the plates project about 3 in. above the top when the press is assembled. The upper portion of the system resembles a long pan with openings at the top of each mould. The molten wax is pumped into a tank from which it gravitates into the pan and through the openings into the moulds. The wax is always at atmospheric pressure and the pressure from the press is applied only for holding the plates in place.

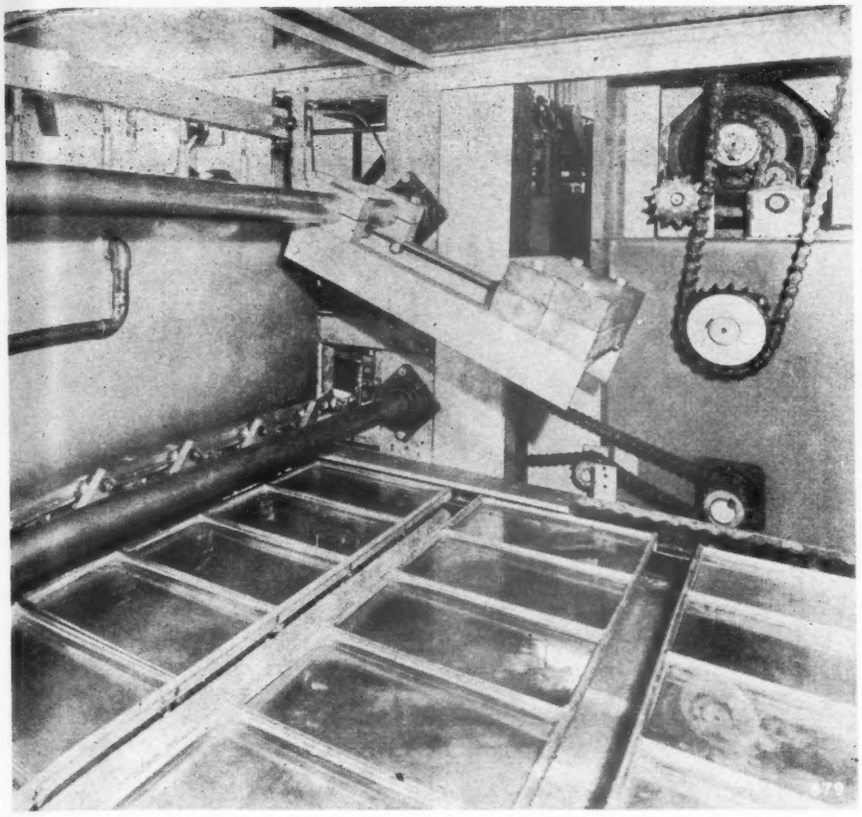
After the moulds are filled, water is circulated through the cooling plates. A layer of liquid wax is maintained in the pan while the wax solidifies. This is necessary because of the uneven shrinkage of the wax cakes, which undergo a 15 to 17 per cent contraction from a liquid just above the melting point to a solid at room temperature. During the solidification process, heat is sometimes applied to keep the wax in the pan liquid, thus insuring its easy flow into the moulds to form relatively uniform cakes. The cooling period lasts from 2 to 3 hours depending upon the melting point of the wax and the temperature of the cooling water. After the cakes are formed, the surplus wax remaining in the pan is scraped off, the press is opened, and the cakes removed manually.

This brief description of the batch moulding process suggests the many inherent difficulties encountered by refineries in operating this rather primitive conventional equipment. The process is slow and expensive, requiring a great deal of manual work. The cakes are often uneven and vary in weight because of the difficulty of maintaining a continuous flow of wax into the moulds during the solidification period and the presence of entrapped air. After the cakes are formed, some wax is lost in scraping off the surplus left in the pan. The necessity of scraping the wax also makes the process sloppy, and the floor area required to accommodate batch equipment is comparatively large.

The shortcomings of the batch moulding process instigated work by the engineers of the Magnolia Petroleum Company to develop improved methods for manufacturing wax cakes. After investigating various possibilities offered by other than petroleum industries—all of which offered some-

Tempering exchangers equalize temperature of molten wax.





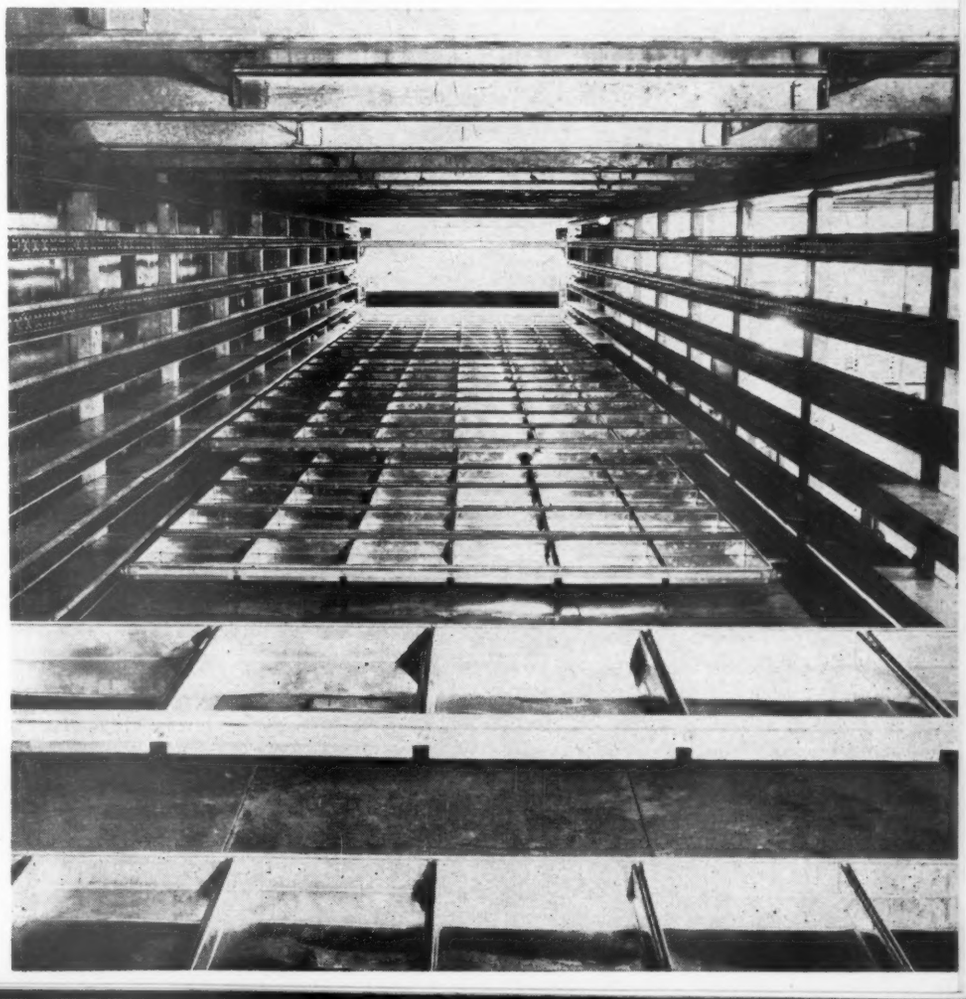
Pans filled with wax moving to cooling chamber.

what similar problems as those in the batch moulding system—the engineers decided that the continuous chocolate moulding machine sold by the J. W. Greer Company, Cambridge, Massachusetts, might be properly modified to offer a solution to the wax moulding problem. Through the joint efforts of the two companies, a continuous wax moulding system was built and put into operation at the Beaumont, Texas, refinery of the Magnolia Petroleum Company.

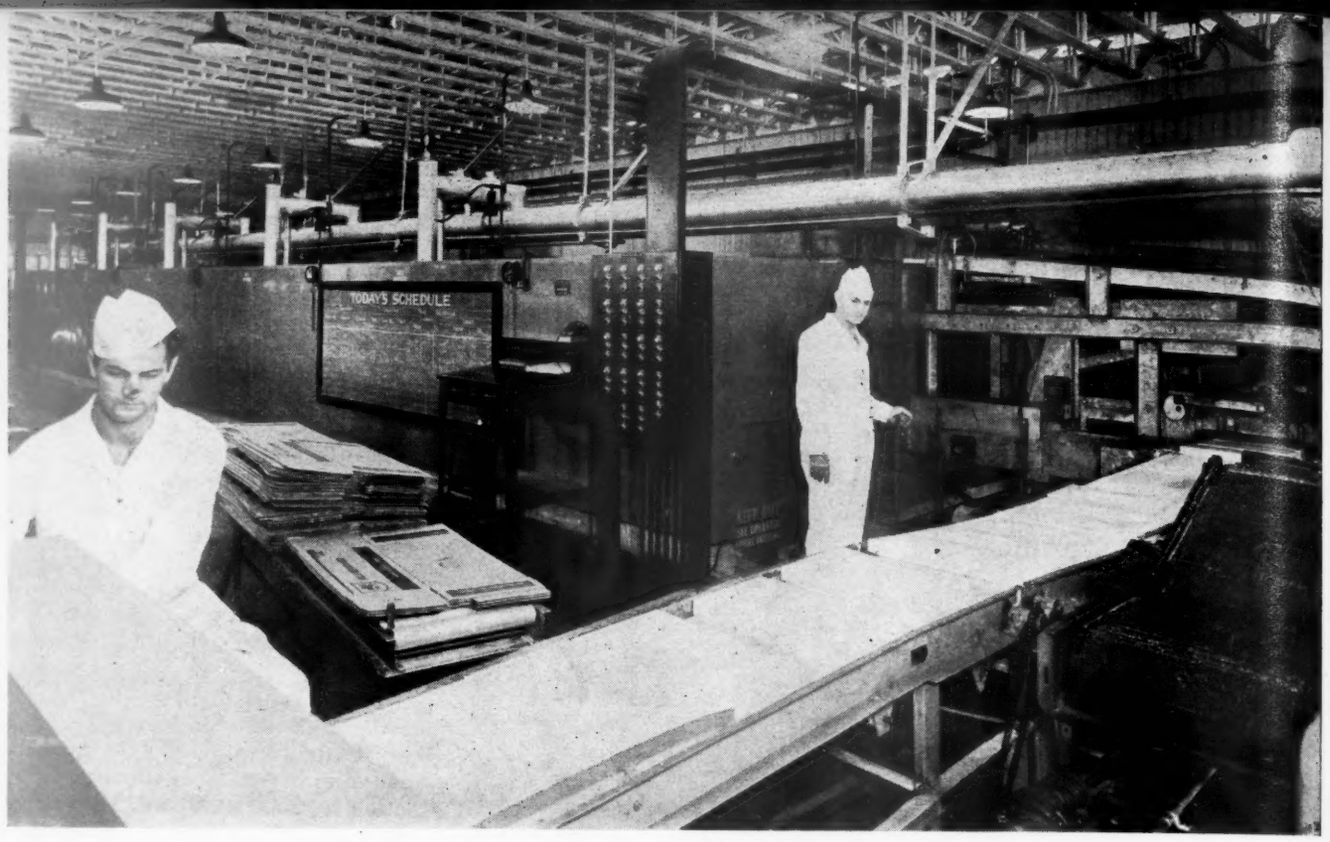
The schematic flow diagram of the process shown in the accompanying illustration reveals the simplicity of this new continuous method for moulding waxes. Here briefly is how the system works. First. molten wax kept in insulated and steam-heated charge tanks is pumped through automatically controlled "tempering" exchangers where its temperature is adjusted somewhere between 140 F and 160 F, depending upon the wax melting point. For best performance this temperature should be as low as possible, provided the wax does not begin to solidify before it reaches the cooling chamber. The tempering exchangers are designed to operate both as heaters or coolers in order to maintain an even temperature of the wax stream regardless of the temperature of the wax in the storage tanks.

From the tempering exchangers the liquid wax is directed to the steam jacketed "depositor hopper." This hopper is an open rectangular tank with a partially sloping bottom. The wax level in the hopper is automatically regulated by controlling the speed of the charge pump. The portion of the hopper having the flat bottom contains 6 pistons, which act as measuring devices for the quantity of wax required to form the individual cakes. The pistons are easily adjustable, having a maximum ability to discharge 12 lb of wax into each pan. After the pistons are set, the weight of the wax delivered into the pans remains constant and varies less than one-half of an ounce between the individual fillings.

The pistons discharge the molten wax directly into the moulding pans, which are 19 in. long, 11¾ in. wide and 2 in. deep. In continuous circulation are 2508 such pans. The dimensions are not critical although they are somewhat limited by the over-all equipment specifications for the individual installations. Considering the minimum permissible thickness of the wax cakes due to their brittleness, the pans of the above size can accommodate from 8 to 12 lb of wax. The moulding pans rest on trays that move on a chain conveyor. Each tray holds 6 pans corresponding to the 6 pistons from which the molten wax is discharged.



Cooling chamber under construction showing position of the lower rows of trays and pans.

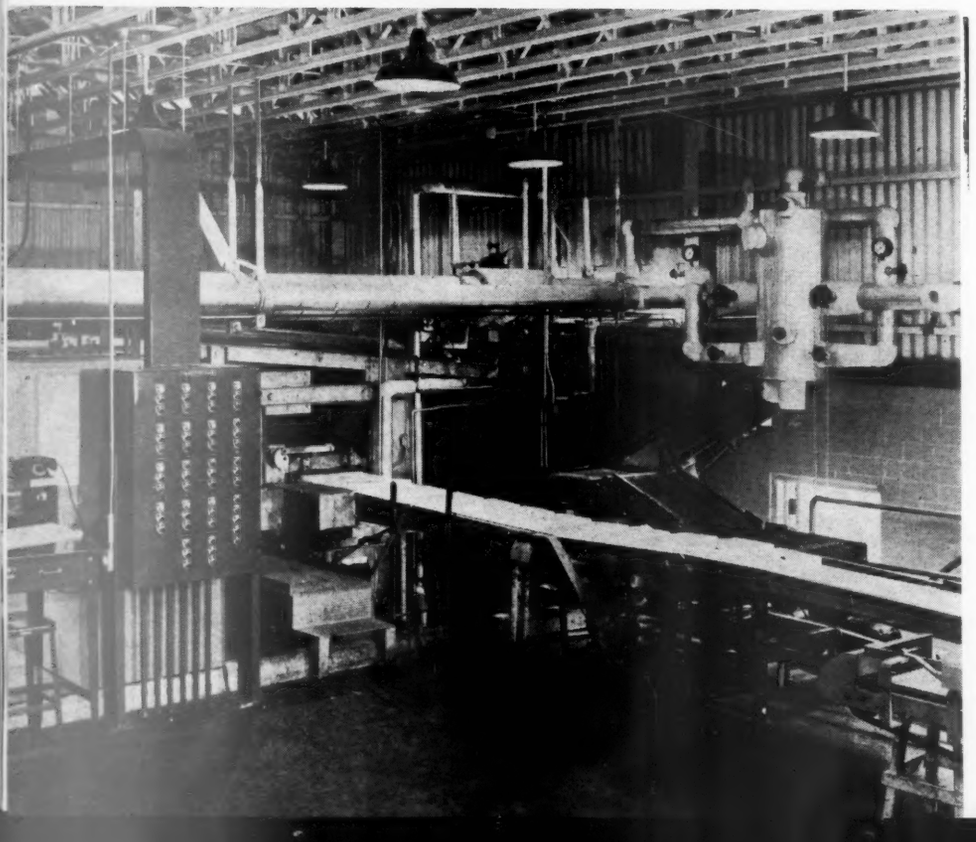


General view of continuous wax moulding plant. Remote control operating panel can be seen in the center.

After the pans are filled with the wax, the trays carry them through cooling compartments where the solid wax cakes are formed. Cooling is done by a stream of cold air supplied perpendicularly to the direction of tray travel. Cold air is obtained by passing the air over 5 dry coil Carrier evaporators connected to a 150-ton Ingersol-Rand ammonia compressor.

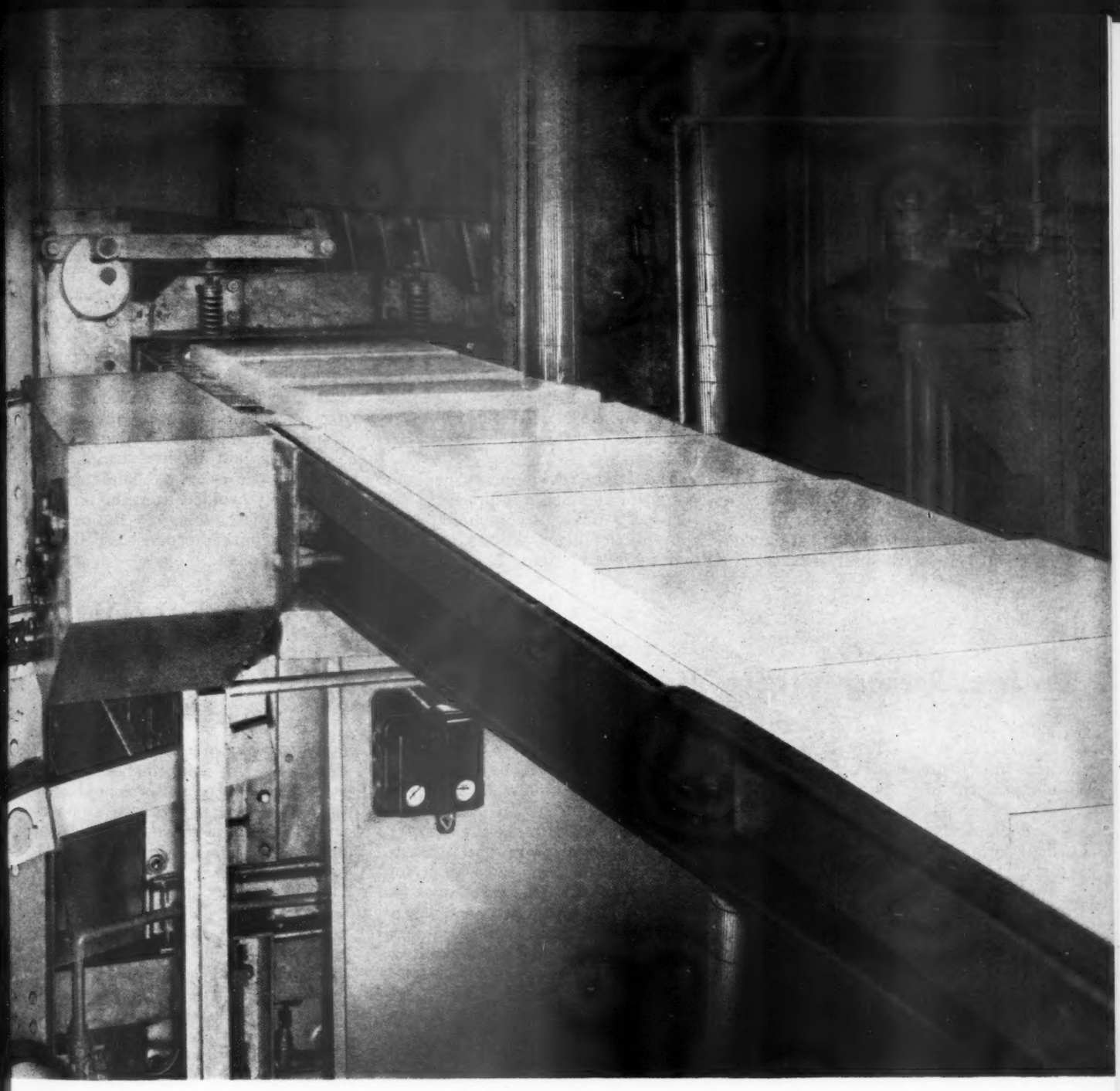
The cooling chamber is completely enclosed and insulated to insure maximum operating economy by recirculating air within the system. For maximum output the refrigerating coils are run at full capacity and the blowers are operated at constant speed. Air temperature is maintained at 20-30 F. The rate of cooling the wax cakes is controlled automatically by varying the speed of the conveyor; it depends upon the melting point of the wax to be moulded. The higher the melting point of the wax, the greater the unit output.

Depositing and discharge sections of moulding unit.



Construction of chain conveyors passing through the cooling chamber deserves further description because of their ingenious design. After the conveyor reaches the opposite wall of the cooling chamber, the trays are automatically lifted and transferred to the next higher level of the same conveyor to move in the opposite direction. This is done without disturbing even to the slightest extent the partially solidified wax in the moulding pans that would result otherwise in wrinkles on its surface. The doubling of the conveyor may be repeated as many times as desired, contributing to the compactness of the design by substituting height for length of the cooling section. In the Magnolia Petroleum Company installation the trays make 14 passes through the cooling section, traveling a total distance of about 800 ft in a space 64 ft long and 10 ft high. The entire moulding unit is driven by one 10-hp motor through a variable speed reduction gear. The residence time of the wax in the cooling section may be adjusted anywhere from 60 to 180 minutes by varying the speed of the main drive gear.

The surface temperature of the wax cakes leaving the cooling chamber is controlled between 60 F and 80 F.



THE GREER CONTINUOUS WAX MOULDING MACHINE

Introducing Continuous Processing of Liquid Wax into Slabs

NOW in actual operation, and available to the Oil Industry, is this revolutionary machine which receives liquid wax from storage tanks — Deposits in Moulds — Cools to a Solid Slab — and Demoulds ready for shipment — *all Continuously and Automatically, without a hand touching it!*

Pictured above is the discharge end of the machine which occupies a space of only 19 x 78 feet — and produces 12,500 lbs. of finished slabs per hour — with a variation in weight of less than ½ of 1%!

Developed and manufactured by the J. W. Greer Company, who for over 33 years have been solving problems of continuous automatic processing in the Biscuit, Cracker, Confectionery, and Process Industries.

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depending on the melting point of the wax. The lower the melting point of the wax, the lower the temperature at which the wax cakes are discharged.

The wax cakes are also removed from the moulding pans automatically. The pans that are attached to the straps are tilted until they are in the upside down position and the cakes drop from the pans. The chain conveyor makes another turn and the trays and pans assume their former positions. The bottoms and sides of the empty pans are heated slightly by passing the trays over an electric heater before starting the next traveling cycle through the system. The wax cakes dropped from the pans are picked up by a belt conveyor.

The original installation included an automatic weighing device for inspecting the wax cakes. This device was soon found to be superfluous, however, because the individual cakes vary less than one-fifth of one per cent by weight from the average. In the conventional batch moulding process, cakes of similar sizes varied in weight by as much as 5 per cent.

The equipment, which has been installed at the Magnolia Petroleum Company, is capable of moulding from 11,000 to 17,000 lb of wax per hour, again depending upon the wax melting point. The wax cakes are exceptionally uniform in size and have a bright luster, appealing to the eye. No wax is slopped except at the very beginning of the operation while the equipment is brought up to equilibrium conditions. This slop wax is returned to a special melting tank for reprocessing.

The labor requirements per unit weight of moulded wax produced was reduced 5 times as compared to the conventional batch process with further savings in sight. The larger the volume of the wax moulded, the greater the savings in manpower.

The appearance of the conventional wax moulding rooms with the wax spilled on the floor and equipment is practically eliminated. The floor space required for accommodating the equipment is not over one-tenth of that normally occupied by the wax moulding presses and may be further reduced, if desired, by increasing the height of the cooling chamber.

The new continuous process is also well adapted for automatic packaging of wax cakes into paper boxes and discharging these boxes directly into the freight cars. This makes the process highly desirable from the sanitary point of view, because handling of wax or wax cakes by hand may be completely avoided from the time the crude oil is obtained by the refinery until the finished product is delivered to the customer. * * *

P 732.4

Insulating While Hot Prevents Expansion Problems†

ENGINEERS at the Disco Corporation, Imperial, Pennsylvania, have solved the problem of expansion cracks in thermal insulation by insulating the high-temperature metal surfaces of their carbonizers and roasters at operating temperatures—up to 1050 F. Thermal expansion from shutdown to processing temperatures adds about 8-in. to the length of each carbonizer and 5-in. to the length of each roaster; insulation installed on the huge units while shut down would be very liable to crack and lose some of its effectiveness. By applying mineral wool blankets and cement to the metal surfaces while hot—at maximum expansion—the insulation covering was fitted at normal operating conditions.

Disco's seven carbonizers (125 ft long and a 9 ft internal diameter each) and seven roasters (6 by 95 by 16 ft each) process over 1000 tons of coal per day to produce Disco, a smokeless fuel from which liquors, tar and gases have been removed. In one illustration, a hot recirculating gas duct, insulated with mineral wool blankets, leads diagonally from a roaster on top to a furnace below the carbonizer. To maintain the delicate process balances under all weather conditions, mineral wool blankets insulate 66,500 sq ft on seven such processing units.

The insulation was applied to all units in 24 by 48-in. blanket sections. On each of the seven roasters, at an average temperature of 750 F, 5000 sq ft of surface area were insulated with a single layer of 4 in. thick blankets. Two 4 in. layers were applied to 4500 sq ft of surface on each of the seven carbonizers at average temperatures of 975 F. The blankets, composed of mineral wool between metal lath and wire netting, were installed with the wire netting against the heated metal.

The insulating blankets were secured by studs, 300,000 in all, welded to the metal on 9 in. centers. The studs were 5 in. long for the 4 in. thick insulation and 9 in. long for the 8 in. thickness. After all the blanket sections were impaled on the studs, galvanized iron bands were tightly wrapped on 12 in. centers around the carbonizers and roasters to ensure a long-lasting insulation cover.

A lock washer was placed over each stud (1 in. end of each stud protruded above the metal lath) and the stud ends were bent over. Over the insulation, a ½ in. thickness of mineral wool insulating cement was applied in two ¼ in. layers. The first layer was trowelled into the metal lath and, after drying, the second layer was trowelled over it.

Then sections of 1-in. wire mesh were stretched over the cement and laced together with 18-gage galvanized iron wire. The mesh covering was secured by auto-clench staples driven into the cement on approximately 12 in. centers. As a weatherproof finish, asphalt mastic was trowelled into the mesh covering to provide a ⅛ in. dry-thickness when dry.

The insulating effectiveness of the mineral wool blankets is indicated by the temperature measurements in the table. The temperatures on the outside insulation surface were measured at three points along a carbonizer and a roaster and are compared with actual metal surface temperatures at the same points. * * *

TEMPERATURE MEASUREMENTS ON OUTSIDE INSULATION SURFACE

Roaster and Carbonizer-Disco Corporation

Point of temperature measurement	Thickness of mineral wool (24 by 48 in. blankets) inches	Temperature at metal surface deg F	Temperature* on outside insulation surface deg F
Roaster			
High end...	4	900	148
Middle.....	4	750	123
Low end....	4	600	119
Carbonizer			
High end...	8	1050	186
Middle.....	8	975	161
Low end....	8	900	143

* Measured with mercury-bulb thermometer completely insulated except for tip against insulation.

†Industrial Mineral Wool Institute.

☆ ☆ ☆

Ralph Basnight, an employee of the Plymouth Oil Company at Plymouth, North Carolina, jumped from an oil company dock on the Roanoke River near Hartford, North Carolina, and rescued a man and a boy after their boat had foundered. Two other occupants of the boat were drowned in this tragedy.

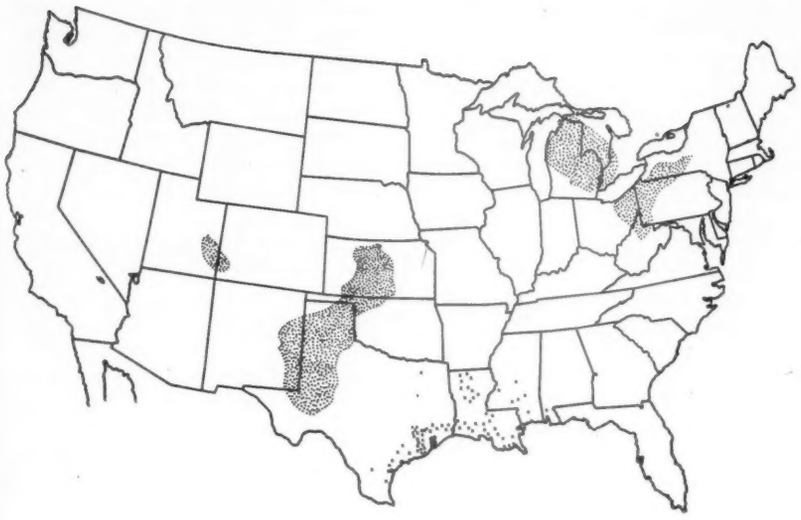


FIG. 1. Underground salt beds and domes.

Underground Storage for Liquefied Petroleum Gases†

Storage of excess LPG in salt domes from which salt has been dissolved proves feasible and practical

FRANK MATHENY*

WE ARE ALL keenly aware of the long existing problem of how to conserve LPG products in off seasons in order to supply our consumers during seasons of peak demand.

Last year from the rostrum of the NGAA Convention in Fort Worth, I made the prediction that by the time of the next convention your storage problem would have been solved. That statement was not conjecture, as we had had under way for a long time a development program to provide economical artificially formed underground storage near manufacturing plants and near consuming markets—and neither one is more important than the other—it depends on which is mentioned first. The development stage of this means of storage is now behind us with the proved commercial use of thousands of barrels of such storage facilities. So far as I personally know, the only manufacturers who did not miss a shipment last winter depended upon such underground storage to fill their own customer requirements—and, incidentally, to help some of their competitors through the trying periods.

The design engineers, the plant operators and the sales departments have been plagued for years attempting to balance supplies and demands. Local area ratios run as high as 6:1, 3:1 is common, and 2:1 might be average. We try to balance high ratio consumers in one area and season against other consumer demands whose peak loads are at another season. Almost every year we have helplessly witnessed seasonable wastage of valuable LPG products and have failed our consumers at the time they need these products most. I doubt if the industry—taken as a whole—can completely absolve itself of the obligation to serve, if segments of that industry have taught a people to depend upon those services. Even today this Association is spending considerable sums to advance further the sales of LPG right in the wake of one of its worst winter performances. I sincerely hope and believe this paper will offer avenues to a more stabilized distribution irrespective of so-called load factors.

Unlike the motor gasoline industry, which for many years has stored all winter to meet summer requirements, the cost of our storage investments has been hopelessly prohibitive. It is believed $20 per barrel or nearly 50 cents per gallon is a representative cost figure for propane tankage, and considering propane values, there is not a whisper of a hope ever to effect a payout on money so invested. The one company that has attempted steel storage to flywheel seasonal demands frankly admits no payout as such is expected. It considers the investment an over-all overhead cost of its extensive marketing operations (and I undertsand they do a good job).

Things are not as bad as all this might sound, however. Since the inception of LPG marketing, forward looking companies, operating personnel, and top flight engineers have been relentlessly pursuing every avenue of promise. Because of the physical character of the product, with its attendant hazards and tankage cost, the weather eye has always been trained toward some kind of underground storage, although other approaches such as refrigerated low pressure, adsorption, and other types of storage, have been thoroughly investigated. Perhaps it might be interesting to review a few of these projects and studies.

One of the earliest used disposal methods was merely converting a low producing oil well on a lease into a butane injection well. If injected in quantities, the butane promptly showed up in the offset wells and a recycle established. Net ultimate recoveries varied from nil to fairly good. I do know of some instances where the effect on crude oil recovery was so startling that one wonders whether petroleum production engineers have followed up the potentialities.

Stray gas sands and depleted gas wells have also been used. Recoveries from some, like the Layton and Pawhuska sands in Oklahoma City, were very disappointing, though La Gloria Corporation reports storage in a 5500-ft inactive gas reservoir as quite successful. Into this reservoir of 1800 lb pressure and 20 per cent porosity has been injected around 20,000 bbl of butane with 62 per cent recovered by flowing, and the well was still flowing marketable product at the end of the withdrawing season. This well was worked alternately for storage and for production as plant sales required. Unofficially I have heard of other gas well storage programs even more remarkable than La Gloria's.

Salt water sands have been a favor-

*Sid Richardson Gasoline Company, Fort Worth, Texas.

†Presented before the 30th Anniversary Convention, Natural Gasoline Association of America, Tulsa, Oklahoma, April 25-27, 1951.

ite hunting ground. Last year we had an excellent paper by C. B. Johnson recounting The Chicago Corporation's experience at Carthage. Johnson now reports that they have improved their technique considerably, that during the past year an additional 105,000 bbl were stored, 22,000 or 21 per cent flowed out by water injection for winter use, comparing favorably with the data presented to you last year. Here is the important difference: At the end of the 1950-51 withdrawal season the well was still flowing 250 bbl per day of marketable product, and that rate was limited by the capacity of the water injection pump. It is entirely possible the major losses have been sustained and The Chicago Corporation now has working storage.

We once stored around 90,000 bbl of butane in the Ruseler salt water section, a porous dolomite, in Winkler County at a depth of 850 ft. When recovery was started approximately 23,000 bbl or 25 per cent flowed naturally. A casing pump was then installed and some 3000 bbl more recovered, making an over-all recovery of a shade less than 30 per cent, with the well still pumping 1000 to 1500 gal per day.

Millions upon millions of gallons have been pumped into the granite wash of the Texas Panhandle with almost instantaneous migration.

Warren Petroleum reports a 25,000-bbl experimental reservoir at one of its Breckenridge, Texas, plants. This chamber was mined from between two impervious layers of limestone at only a fraction of the cost of equivalent steel tankage. The corporation's engineers report no difficulty was encountered in either the storage or the removal phases of operation during commercial use over the last business cycle. While they consider it highly successful their engineers point out the major prerequisite to general use of such reservoirs is the discovery of formations that are dry, impervious, unlikely to contaminate products, and with an overburden of heavy density and sufficient structural strength to permit mining without supports. This roof formation they report should not be less than 150 ft or more than 500 ft from the surface.

Low pressure vessels plus refrigeration have been estimated for all pressure levels. In addition to operational hazards the economics always point to pressure vessels, though it is possible, where a plant has idle equipment, refrigeration could be cheaper.

Adsorption on charcoal or similar materials with provision for revaporization and condensing has been evaluated, but again the economics say steel tanks.

This review brings out the fact that industry has for years been searching for a solution to its storage problem, and where local conditions have been right, remarkable progress has been made; maybe the rest of us just have not looked hard enough.

In light of the geographical location of salt beds and salt domes with respect to manufacturing plant locations, transportation facilities, and ultimate markets, and in light of the cost and performance of commercial storage reservoirs in these sale sections, it does appear the nearest approach to an over-all solution to the industry's storage, transportation and marketing problems lies in the extensive use and strategic location of salt section reservoirs.

On Fig. 1 is depicted the location of these beds and domes as assembled from many sources of information. Note the massive beds of the Permian Basin Area underlie practically all of the West Texas, New Mexico, Panhandle and South Hugoton extraction plants. All of these plants have storage under their plant sites to accumulate off season surplus to meet all peak season local demand, and those fortunate enough to have LPG pipe line outlets can leave their products under their plants until the pipe lines call for it.

Note that the gasoline and recycling plants around the coast from South Texas to Mississippi are literally interspersed with salt domes. In Eastern Louisiana, in Mississippi and Alabama, the territory whose consumers probably suffer most from winter famines, note that this section of the Southeast has salt domes almost ideally situated to markets. What would be more logical than to use your tank cars all summer moving surplus LPG into this area, then serve the local consumers through the use

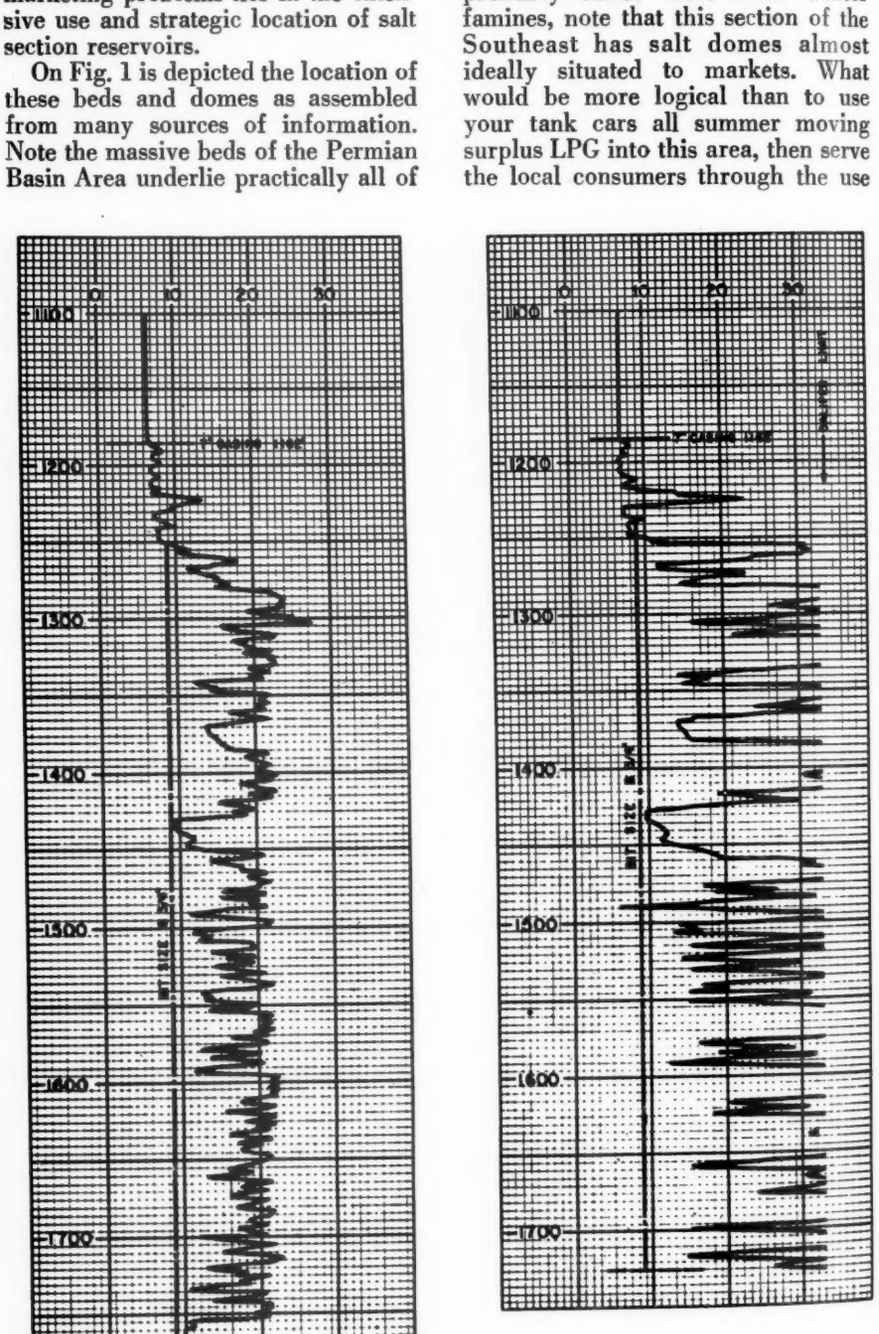


FIG. 3. Caliper surveys, 25-hr circulation on left and 50-hr circulation on right.

of dealers' trucks all winter—diverting the tank cars to other hauls? In fact, some of the Southeastern dealers, veterans of the famine or feast market, are today busily engaged in installing thousands of barrels of underground storage in these domes.

Observe the salt beds in Michigan, Ohio, Western Pennsylvania, and into Western New York. Here are storage areas near both domestic and industrial markets.

How to go about installing one of these reservoirs? We have found that most of the required information in the oil country can be had by inspection of oil or gas well logs, the remainder such as availability of water, salt disposal, desired capacities and withdrawal rates are readily obtainable in each locality. For brevity the procedure at Richardson's Kermit plant will be described since it offered problems not encountered in the salt domes.

Fig. 2 shows schematically the log of the salt section and cross section of the reservoir. Note that though the whole section is over 600 ft thick, there are strings of anhydrite and shales scattered throughout. Observe also the 1250-ft ledge of approximately 20-ft thickness and the similar one at about 1450 ft; more will be said about these later.

An ordinary jackknife rotary rig was moved on to the location, fresh water casing set and cemented at 350 ft, then the well was drilled to a total depth of 1770 ft, 9⅝ in. casing was cemented in the anhydrite as 1162 ft —about 110 ft above the top of the salt section and 2½ ft upset tubing bottomed at 1748 ft or 22 ft off bottom. The drilling rig was then moved off and the water circulating pump set and connected to the plant water system from which 3000 to 5000 bbl per day were available. The land in this area is quite arid and was owned in fee by the plant, so that for salt water disposal an earthen dike was thrown up adjacent to the well and circulation started. Generally, water was pumped into the well through the annular space and displaced from the bottom through the tubing in order to carry out the insoluble salts and small particles from the caving shales.

As anticipated the anhydrite stringers at 1250 ft and 1450 ft did not dissolve resulting occasionally in fines stopping down-circulation between the well bore and the tubing. In these cases circulation was reversed, pumping water into the tubing to flush the fines out. Occasionally particles lodged so firmly over the mouth of the tubing as to practically stop circulation. These were dislodged by reversing circulation. (I will add, however, that before using the reservoir

Soda Sweetening Process at Palembang

A description of the operations, and actual figures on costs and savings at the Palembang refinery of Standard-Vacuum Petroleum Mij. in Indonesia, are contained in a paper delivered before the Third World Petroleum Congress at The Hague. The paper, entitled, Gasoline Sweetening Operation at Palembang Refinery, was written by E. C. Campioni, superintendent, technical service division, and P. J. Cordia, process engineer of Standard-Vacuum's technical service division in Sumatra.

Campioni and Cordia describe the double-stage soda sweetening process this firm has developed to sweeten the 6-8 copper number gasoline. In the new process, the sour gasoline is consecutively treated with a weak and strong caustic soda solution. The weak solution is made up by diluting the partly spent strong soda effluence, and after being spent is discarded.

FIG. 2. Typical cross-section of well and reservoir.

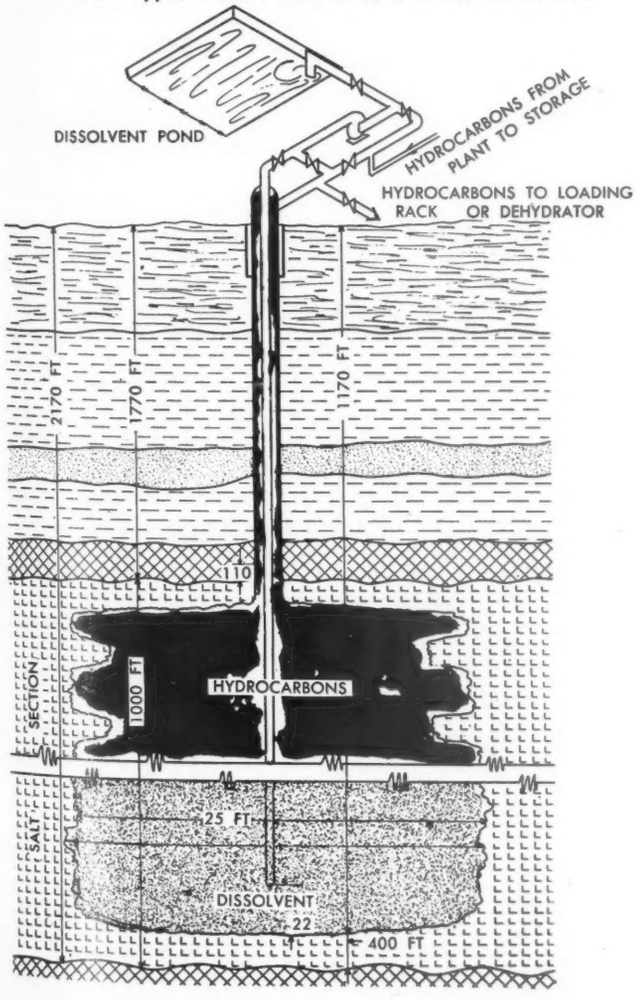
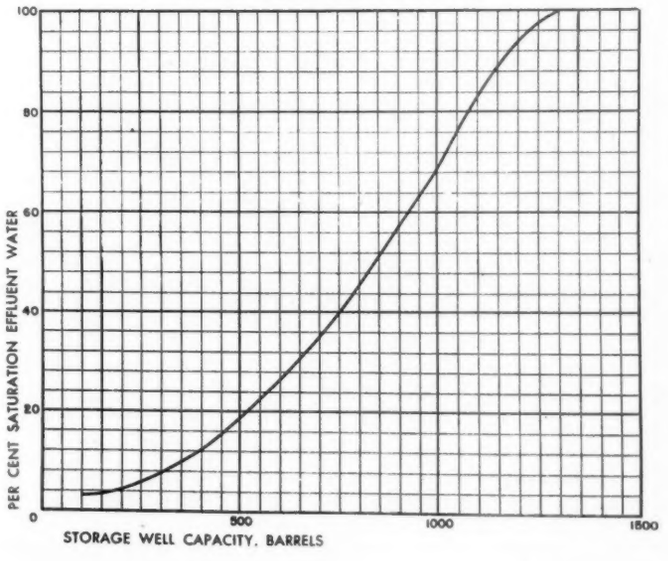


FIG. 4. Expected percentage of saturation of the effluent water vs reservoir capacity.



again for storage, we will pull 2½-in. tubing, shoot out the 1250-ft anhydrite, and reset 5-in. tubing above the 1450-ft stringer.)

Until the diameter became too large, Halliburton ran mechanical calipers at intervals. Fig. 3 shows on the left the caliper survey after 25 hours' circulation and on the right after 50 hours. Though the insoluble anhydrite stringers appear acute on both of these, note radical difference in the horizontal and the vertical scales. If the drawing could depict a section 2000 ft long and 30-40 in. wide these ledges would appear quite smooth.

Circulation was continued until the reservoir was needed then filled to meet winter peak requirements. As many as 15 cars per day were loaded directly from this reservoir by pumping water down the tubing. Friction loss through the 2½-in. tubing controlled the withdrawal rate which resulted in the decision to replace the 2½-in. tubing with 5-in. Without means of actual measurements we speculate the over-all underground reservoir to be somewhat like Fig. 2.

Other items in which you might be interested will be mentioned briefly.

Upon completion of the drilling operations and setting of casing and tubing, a pressure test will, in our opinion, confirm or deny your possibilities. Care must be taken here to apply test pressures well under those which would break down the formation. In fact, the pressure gradient is the key to installation and to the use of all underground reservoirs.

There is no practical difference between using water at atmospheric temperatures as against hot water. For example at 60 deg and 100 per cent saturation it requires 6 bbl of water to remove 1 bbl of salt, whereas at 120 deg it still requires 5.86 bbl of water to dissolve 1 bbl of salt. Forgetting temperatures and averaging out low saturations during initial circulation with full saturation after contact space is provided, a figure of 6.3 bbl water per barrel of reservoir made is a good rule of thumb.

Experience confirms the theory that the capacity of the reservoir can be quite accurately estimated by metering the fresh water, taking periodic test on the effluent with a brine calibrated hydrometer and then from a prepared solubility curve, calculate the salt removed or the reservoir space added. Fig. 4 illustrates the expected percentage of saturation of the effluent water vs reservoir capacity.

The relative difference in cost, percentagewise, of the first, second, and third reservoirs, all in the same general area and structure, and based on the same theories, was alarming—even though the highest cost reservoir was exceedingly profitable.

Costs are of a relative dimension. It is obvious that the size of reservoir, location, depth of beds or domes, desired recovery rates, etc., all have their influence. It is also obvious that most of the money is spent before water circulation even starts so that the per barrel investment varies inversely with size. A 100,000-bbl reservoir should be installed in West Texas for ± $50,000 or around 50 cents per barrel. A 500,000-bbl reservoir adjacent to the Mississippi River might go in for $75,000 or 15 cents a barrel. Too, they are like a bathroom in that the fancier you want the trimmings, the more it costs.

Pumping pressures and costs at Kermit compare favorably with ordinarly plant to tank car operations. Depth of reservoir and size of tubing being the controlling factors, required pressures and attendant horsepower lend themselves to calculation for any location.

Every effort has been made to acquaint the industry with the possibility of these reservoirs. Public demonstrations have been held where visiting engineers could observe the steel tank gauges, the injection pressure, injection rates, dead storage pressures, withdrawal pressures, inspect product specification before, during and after withdrawal and finally confirm for themselves the 99+% return to steel tankage of products so stored. Except for the loss of around 50 bbl the first time used (which we attribute to erosion of the ceiling above the casing seat) any loss experienced has been in the order of the error of tank gaging. The National Security Resources Board has seen fit to send Army and Air Force officers down to observe, and to evaluate the process for military usage. The British Government has sent its representatives out. Articles have appeared as news items in Fortune, The Oil and Gas Journal, Journal of Petroleum Technology, Chemical Engineering, newspapers, private literature and the process has been brought to the attention of many potential users through personal contacts.

Extensive work has been done and is still being done which indicates soluble shales are as effective for storage purposes as are salt beds—but that might be another paper.

The time is long past for us to consider the LPG industry as a by-product, a side line, or a seasonal business. While not among the biggest, this industry is definitely big business and is now a necessity of life for millions of people and thousands of other industries. It is an industry performing a service in which every manufacturer, every jobber and every dealer can take pride in his contributions.

In conclusion, I would like to say that you now have, or have within reach of your cable tow—a ridiculously cheap method of storing your LPG products (or any other hydrocarbon), and this year's prophecies for the LPG industry are:

1. You are going to save many dollars in investments while saving for other use untold tons of steel.
2. The flaring or wastage of these products will cease.
3. You will, like the motor fuel manufacturer, as a matter of business routine, accumulate product in off use season to fill consumer requirements in peak seasons.
4. You will placate the anxiety of present and potential LPG users occasioned by the feast-famine record behind us. In other words, stabilize the most turbulent market in the petroleum industry.
5. You will save yourselves a lot of headaches while making a lot of money for yourself, your royalty owner, your dealer, and yet save the ultimate consumer money and extreme inconveniences. ***

Oil Circulation Processes Described

Some important advantages in operation of the Fischer-Tropsch synthesis were discussed in the paper, "U. S. Bureau of Mines Fischer-Tropsch Pilot-Plant Studies of Oil-Circulation Processes," by H. E. Benson, J. M. Crowell, J. H. Field, and H. H. Storch. Presented before the third World Petroleum Congress, the paper gives full details of results of several experiments to develop the oil-circulation process.

The paper summarizes the Fischer-Tropsch process development, and the essential features of the German fixed-bed system, the hot-gas recycle and oil circulation process, and the oil-slurry and fluidized-bed system.

The Fischer-Tropsch synthesis by the moving-bed oil-circulation system seems desirable because it can use feed gases of approximately 1 : 1 H_2 : CO ratio that are readily and more cheaply produced from coal than are synthesis gases high in hydrogen. It is felt that the flexibility of the operation of the moving-bed oil-circulation system may offer the best possibility of more economic synthesis gas usage.

Improved Spark Timing Light*

ONE of the most useful methods of rating the antiknock values of gasolines on the road is by means of the Borderline Road Knock Test procedure[1] or by modifications thereof. (See Fig 1 for typical knock curves.) To obtain road knock test data by the Borderline procedure, the test car must be equipped with a means of controlling and indicating the engine spark advance from within the car while it is in operation on the road. One of the most convenient methods by which this can be accomplished is by reading the actual spark advance from a flywheel protractor illuminated by a spark timing light triggered by the ignition system.

Deficiencies of Standard Lights

Some conventional spark timing lights sold commercially can be used for this purpose but have several operating deficiencies. These include:

1. Misfiring of the timing light during engine deceleration and at extreme advanced or retarded spark settings.
2. Misfiring of the spark plug because of leakage of the spark voltage across the timing light.

*Du Pont petroleum laboratories.
[1]Test procedure, CRC Designation F-8A-943, is described in detail in the "CRC Handbook—1946," page 87.

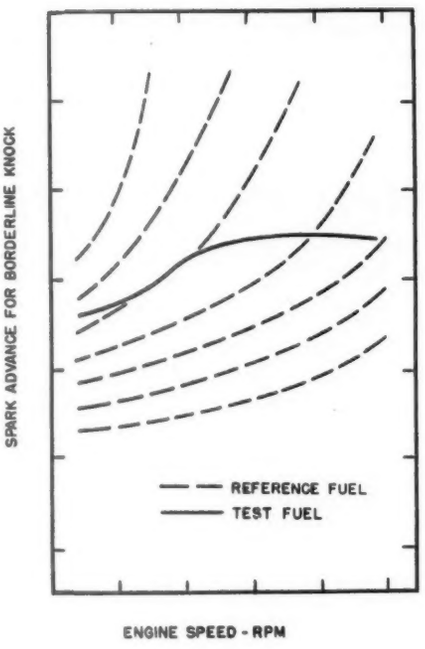


FIG. 1

An analysis of the problem has shown that timing light malfunctioning is caused by (a) reduced ignition voltage under certain engine operating conditions and (b) creation of an electrical leakage path for the spark plug voltage by dirt or moisture accumulated on the flash tube. These effects could be eliminated if the timing light circuit were entirely divorced from the ignition system. This has been accomplished with an improved spark timing light developed by the Du Pont petroleum laboratory by utilizing a thyratron tube relay circuit, activated by induced voltage from a spark plug lead, to trigger the timing light flashes in a separate circuit.

Improved Spark Timing Light

The circuit diagram of the improved spark timing light is given in Fig. 2. A Mallory power pack is used to provide high voltage for the Sun white type flash tube and, through a voltage divider circuit, the thyratron tube. In the normal operating condition, the thyratron tube does not transmit any signal. However, a metal plate clamped on a spark plug lead acts as a capacitive pickup and transmits a trigger signal of 50 to 100 v to the grid of the thyratron tube each time a high voltage pulse passes through that particular spark plug lead. This trigger pulse causes the thyratron tube to fire, discharging condenser C_1 through the primary winding of the induction coil, inducing in the secondary of the coil a voltage pulse of approximately 1000 v, which triggers the flash tube. The oscillation in the primary circuit of the induction coil

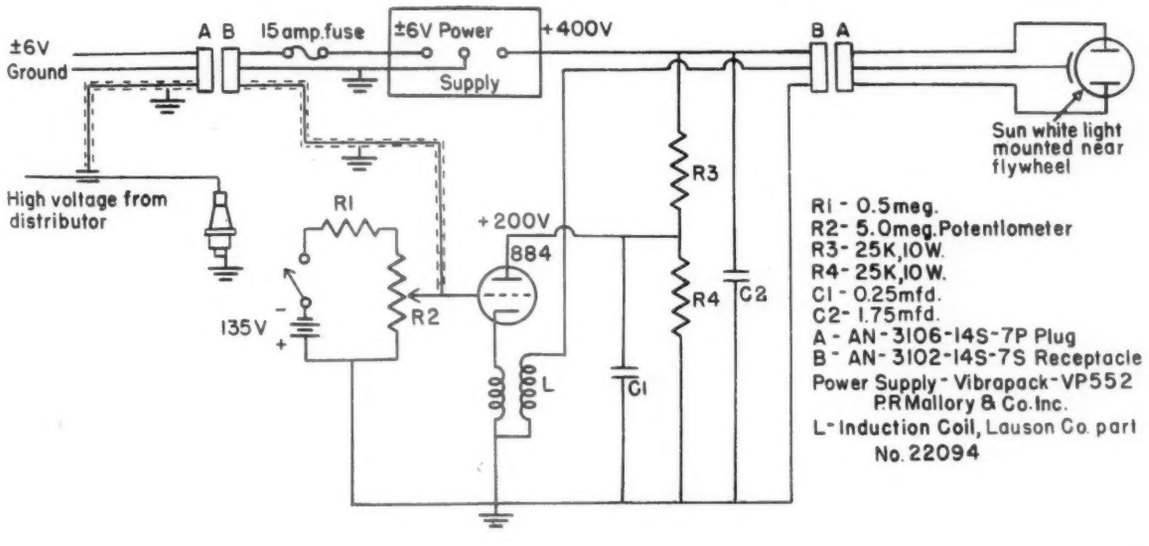


FIG. 2

immediately cuts off the thyratron tube and returns the circuit to a normal state for the next trigger pulse.

The following two simple adjustments are required to make this timing light operate on any car:

1. In accordance with the instructions printed on the Mallory power supply, position the vibrator for operation on a positively or negatively grounded automotive ignition system, as the case may be.

2. Adjust the thyratron tube bias to an intermediate value so that extra flashing does not occur at idle operation and the flash tube does not misfire on rapid deceleration of the engine.

With these two adjustments, the timing light is adaptable to any commercial automotive ignition system.

It has been determined that spark timing measurements made with this unit are identical with similar measurements made by other methods. Considerable use in road knock test work has shown this instrument to have the following advantages over commercial spark timing lights:

1. Equally brilliant and steady timing flashes are obtained regardless of engine speed, spark advance, and condition of the ignition system.

2. The spark plug voltage is not shorted by the timing light regardless of its operating condition. * * *

P 732.4

Two Ways to Insulate Flanges, Valves, and Fittings

RICHARD L. DAVIS*

PIPE flanges, valves, and fittings are often the most extravagant heat wasters in the entire refinery or petroleum processing plant. For the simple reason that their odd shapes make them appear difficult to insulate, these members frequently remain uncovered and radiate heat to the surrounding atmosphere with resulting overheated work areas and higher fuel costs. Engineers and insulation contractors, however, have developed at least two easy ways to insulate these members—the "notched block" technique and mineral wool cement method.

The "notched block" technique comprises the following four steps: (see Fig. 1)

1. Cut and notch blocks of mineral wool to conform to the given contour.
2. Wire the blocks in place with 16-gage galvanized wires or wire bands.
3. Apply a ¼ in. coat of mineral wool cement, troweling it well into cracks between adjacent blocks.
4. Apply finishing materials to conform to neighboring pipe-insulation. For example, canvas jacket indoors; sheet-metal jacket, roofing felt, or asphaltic finish outdoors.

*Secretary, Industrial Mineral Wool Institute, 441 Lexington Avenue, New York 17, New York.

The cement method requires simply that mineral wool insulating cement be applied to the flange, valve, or fitting to the thickness of adjacent pipe insulation. Insulating cement is applied in successive layers ¾ in. or less in thickness to allow thorough hardening. When the desired thickness has been built-up the same finishing materials are applied as are used to finish adjoining sections of pipe insulation.

To illustrate the savings which can be effected by proper insulation of flanges, valves, and fittings, let us assume a typical example of ten sets of 6 in. companion flanges having a bare surface area of 1.82 sq in. each and operating at 350 F. Assume each flange is insulated with 2 in. insulating cement.

The bare heat loss = 798 Btu by 1.82 sq ft by 8760 hr/per year = 12,722,514 Btu/per year (Kent, Page 3-64).

The insulated loss = 64 Btu by 2.73* sq ft by 8760 hr/per year = 1,530,547 Btu/per year (Kent, Page 3-67).

Subtracting: 12,722,514 less 1,530,547 = a saving of 11,191,967 Btu/per year.

*50 per cent added to bare surface area to get outside area after insulating.

TABLE 1. Recommended minimum insulation thicknesses.

Block or Board Insulation		Insulating Cement†	
Temperature F	Thickness inches	Temperature F	Thickness inches
Up to 200	1	Up to 200	1
200 to 400	1½	200 to 400	1½
400 to 500	2	400 to 500	2½
500 to 600	2½	500 to 600	3
600 to 700	3	600 to 700	3½
700 to 900	3½	700 to 900	4
900 to 1,100	4	900 to 1,100	4½
1,100 to 1,300	4½	1,100 to 1,300	5
1,300 to 1,500	5	1,300 to 1,600	5½
1,500 to 1,600	5½	1,600 to 1,800	6½

Assuming the use of fuel oil having a heat content of 145,000 Btu/per gal and an operating efficiency of 60 per cent, the saving is equivalent to 1,286 gal of oil saved per year. At present insulation, labor, and fuel costs, the installation would pay for itself in about ten months.

Table 1† gives recommended mineral wool cement and block thickness for this type of application. Figs. 2 and 3 show typical flange, valve, and fitting insulation jobs.

†Commercial Standard CS117-49, "Mineral Wool Insulation for Heated Industrial Equipment." Single copies available free from the Industrial Mineral Wool Institute. * * *

FIG. 1. A, pipe insulation; B, block insulation; C, No. 16-gage galvanized wires; D, insulating cement.

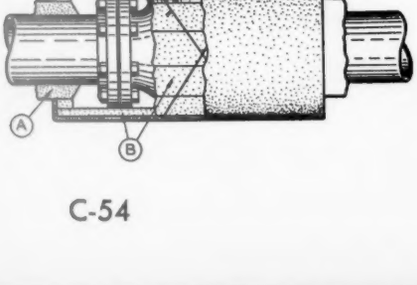
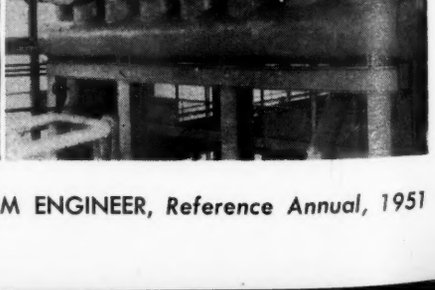


FIG. 2. Flanges and valves comprise a large overall surface area that can waste many Btu's.

FIG. 3. Typical valve insulation problem—insulation of manifolds.



Converting Crude Lines to Products Service*

What are the relative merits of reclaiming an old line and constructing one of new steel? Here is what one company did

EARL W. UNRUH

SINCLAIR Pipe Line Company in the last 10 years has placed in operation 2841 miles of refined products pipe lines of which 1624 miles are composed of either reconditioned and relaid crude oil lines or lines converted in place from crude oil service to refined products service.

Having gone through the numerous "headaches" and problems incident to the use of crude oil lines for products service it has been requested that this paper be prepared to give the products pipe line industry some of the highlights of Sinclair's experience.

Historical

A brief summary of the projects built by Sinclair will show in chronological order the magnitude of converted lines now in products service.

Sinclair began its products pipe line system with the construction of 454 miles of 8-in. and 6-in. pipe from its Marcus Hook, Pennsylvania, refinery. The termini of these lines are Baltimore, Washington, D. C., and Steubenville, Ohio. These lines were constructed with new pipe.

During the past war an 8-in. line was laid at the request of the Petroleum Administration for War from Chicago to Toledo, a distance of 232 miles to supplement tanker movement on the Great Lakes, which movements necesarily are seasonal. This line was constructed in 1943-1944 with pipe taken up from Sinclair crude oil service from various points in the Mid-Continent area, wherever 8-in. pipe was available.

Shortly after the war in 1946, an 8-in. line was constructed from Corpus Christi to Austin, Texas, via Victoria and Luling, Texas, with a new 6-in. branch line to San Antonio. The pipe for this 8-in. line was reclaimed and reconditioned from the rice fields of South Texas, as well as other points in the Mid-Continent area.

Following the construction of the line from Corpus Christi a line was projected from Houston to Kansas City. The first section of this line from Houston to Arlington (Fort Worth-Dallas area), Texas, was constructed of new 10-in. pipe. The section from Arlington to Shawnee, Oklahoma, a distance of 180 miles, was laid using reclaimed 8-in. pipe that had been in crude oil service in the Mid-Continent area.

From Shawnee to Kansas City existing sections of 8-in. pipe were isolated and converted to products use in place. This section of the line is 346 miles in length.

In 1949, existing sections of line selected from the newest of the multiple-line crude oil system were isolated from Chicago to Kansas City. This portion of the system was converted to products use in place using water pressure to blow out pits and weak sections. This was the extent of reconditioning work on the portion of the system converted in place.

Shortly after these sections were placed in operation, sections of line were isolated and converted in place from the Wood River area into Carrollton, Missouri, where the line joins with the Chicago-Kansas City section. Upon the acquisition of the Wood River Oil and Refining Company properties by Sinclair in 1950 this line was placed in products service from Wood River to Carrollton with products being fed into the Kansas City area or the Chicago area as requirements dictate.

The lines described represent a total of 1624 miles of products pipe lines either converted from crude service in place or reclaimed, reconditioned, and relaid for products use. From the experience gained in these ventures, the autnor wishes to present some of the physical problems involved as well as an analysis of the economics of this type of construction, with the hope that the material presented may be of some assistance to others who are contemplating similar conversion projects.

Take-up and Relay

The Necessity of Running Scrapers. The primary consideration in converting a line from crude to products use is to clean the residual black waxy deposits out of the line as quickly as possible. The first procedure is to run a number of scrapers in the crude stream before taking the line out of service. The purpose of this maneuver is obviously to get as much of this deposit into suspension or solution as possible relieving the following products from excessive contamination and discoloration. If the crude line is an old screw-joint line, there will be a considerable amount of paraffin and "B.S." that has settled out in the voids in the screw joints. Scrapers help to loosen this paraffin and carry it in suspension into the nearest tank farm or refinery.

If a high gravity, sour crude oil is available, large tenders of this oil will assist in removing the solidified waxy deposits. It is of prime importance to get as much of the solidified crude oil products out of the line as possible prior to conversion particularly if the line is to be taken up and relayed.

The Author

Earl W. Unruh, chief engineer of Sinclair Pipe Line Company, joined the Sinclair organization in 1938 serving for three years as gas engineer in the Tulsa office. In 1941 when the Sinclair Products Pipe Line organization was formed, he was transferred to Harrisburg, Pennsylvania to assist in the engineering and design of Sinclair's first products pipe line. After the completion of this line, he served in the capacity of chief dispatcher for a year until additional products projects were proposed at which time he was made chief engineer of the products pipe line department of Sinclair Refining Company. In 1948, shortly after the headquarters of the products pipe line department was moved to Independence, Kansas, he became chief engineer of both the crude oil pipe line department and the products pipe line department. On January 1, 1951, these two departments were merged to become Sinclair Pipe Line Company.

Unruh received his early education in the Halstead, Kansas, public schools. He received his A.B. degree with a chemistry major from Bethel College in Newton, Kansas. Upon graduation from Bethel College, he entered Tulsa University and received his chemical engineering degree in 1939.

*Presented before American Petroleum Institute, Products Pipe Line Technology Conference, Atlanta, Georgia, May 21-23, 1951, under the full title 'Converting a Pipe Line from Crude Oil Service to Refined Products Service."

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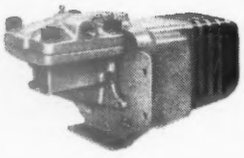

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SINCLAIR PRODUCTS PIPE LINE SYSTEM

Water displacement will invariably set and harden the waxy components throwing the burden of cleaning upon the initial tender of solvent and upon subsequent tenders of products.

Displacing the Oil. If the crude oil line to be converted is an integral part of a multiple line system, a considerable amount of work must be done at each gate plant and pumping station to isolate the line preparatory to take-up and reconditioning. To effect this isolation and removal with a minimum of hazards, it is necessary to displace the oil with water. This must of course be done under any circumstances to recover the "line fill" of oil.

Suitable points must be selected where water is readily available from rivers and a connection must be made available for pumping water into the line. Large volume, high head portable pumps must be set at these locations. Where possible, several scrapers or "Squeegee Pigs" should be inserted in the first part of the water stream to insure as complete displacement of the oil as possible. The oil should be displaced into the nearest available tank where the oil-water mixture can separate and the water can be drawn off and disposed of. It is needless to say that this operation must be carried out during the time of year when all danger of freezing is past.

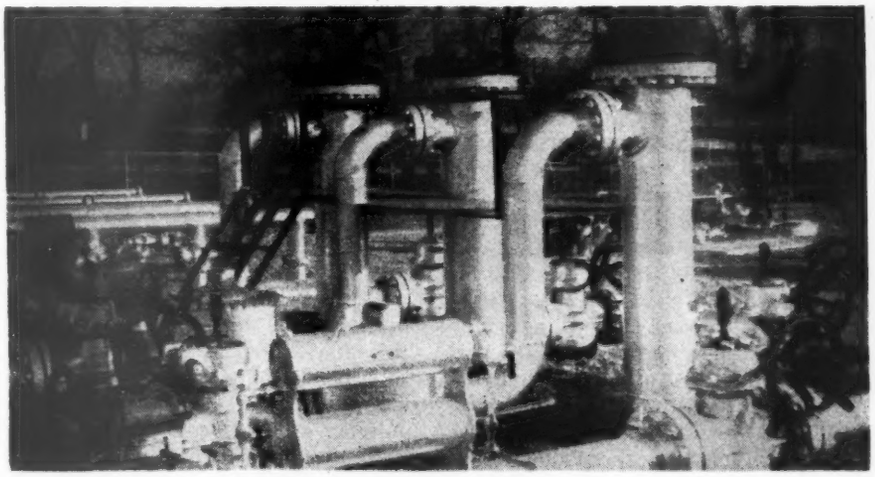
Disposal of Contaminated Water. The problem of disposal of the water at the time of take-up of the line is serious particularly in cultivated areas. Compressed air to displace the water is extremely dangerous because there is usually enough oil remaining in the line to form explosive vapor-air mixtures. The water will carry a film of oil. A thorough knowledge of the profile of line is necessary. The line must be cut or parted at the low points where water drainage can run off without damaging the land or contaminating streams or water reservoirs. The line must also be tapped at the high points in the line to allow air to enter the line.

Take-up and Reconditioning Operations. Preparing to remove the line for reconditioning involves the usual stripping of the cover either by a ditching machine, back-hoe, or rooter. If the line is a screw-joint line, the collars must be cut with a torch. The pipe may be pulled up with a side-boom tractor after the earth covering has been stripped away. Care must be exercised to avoid as much unnecessary bending of the pipe as possible, as straightening operations are costly and time consuming.

The pipe must be loaded and hauled to a central cleaning and reconditioning yard situated at a railroad spur if pipe is to be shipped long distances. At this point the pipe is straightened if necessary and run through a cleaning machine. A most satisfactory machine for yard cleaning has been developed by Sinclair. A picture of the machine in operation is shown. After cleaning operations, the pipe must be inspected and graded being marked for pit-welding operations.

At the time of pit-welding, the ends that were threaded are cut off and in the same operation the pipe is beveled for welding. The length of the screw-joint pipe is ordinarily 20 ft per joint. In order to handle the pipe economically for shipment and relaying, it is double-jointed by welding in the reconditioning yard. After final inspection, the pipe is loaded for transshipment to the location of the proposed products pipe line. Sinclair's experience on take-up and reconditioning shows that approximately 85 to 90 per cent of the pipe can be salvaged for re-laying.

Economics of Reclaiming and Reconditioning Pipe vs. New Pipe. During recent times numerous considerations other than pure economics have entered into the decisions to use reclaimed lines. During the last war, as well as in the present



View showing strainers necessary for removal of mill scale when line is initially placed in operation.

state of emergency, the problem of the availability of steel especially in smaller sizes or pipe is a serious consideration. The tabulation given in Tables 1 and 2 is a comparison of the costs of construction and of operation of a new line versus a reclaimed line.

It should also be pointed out that it is difficult to obtain the same hydraulic line efficiency with reclaimed pipe that is possible with new pipe particularly if there has been some internal corrosion while in crude oil service.

It should also be noted from the foregoing estimate of operating costs that the limiting maximum allowable operating pressure of 800 psi increases installation costs as well as operating costs considerably.

It will be noted in the tabulation that the actual construction figures available cover the costs of construction during 1947 and 1948 as shown in the first column. In the second column are reflected costs estimated for new line construction. At the bottom of the tabulation is an estimated price increase index for 1951 as compared to 1947, to bring the comparison up to date.

TABLE 1. Actual cost of reclaiming and relaying pipe versus estimated cost of new line.

(Estimate based on 8 in. line) 1947 Prices

ASSUMPTIONS	Reclaimed line	New line
Line length	375 miles	375 miles
Throughput capacity daily, gasoline	30,000 BPD	30,000 BPD
Pumping stations	8 @ 800 psi	5 @ 1,280 psi
Wall thickness	0.322i n.	0.250 in.
CONSTRUCTION COSTS		
1. Displace oil	$ 20,000	$.....
2. Take up, haul to yard, and clean (per foot of pipe recovered)	1,090,000	.....
3. Pit weld and double joint	180,000	.....
4. Damages (old line)	80,000	.....
5. Inspection and loading	75,000	.....
6. Rights-of-way and damage	600,000	600,000
7. Pipe (book value of old line)	260,000	1,980,000
8. Casing, vents, and markers	80,000	80,000
9. Freight	390,000	450,000
10. Installation cost (line pipe)	1,750,000	1,750,000
11. Protective coating	360,000	360,000
12. Cathodic protection	30,000	30,000
13. Tank lines and manifolds	50,000	50,000
14. Pumping stations	960,000	600,000
15. Tanks	250,000	250,000
16. Real estate	37,000	25,000
17. Communication system	250,000	250,000
18. Vehicles and work equipment	20,000	20,000
19. Supervision and engineering	200,000	200,000
Total estimated cost	$6,682,000	$6,645,000
Estimated cost per mile	$ 17,800	$ 17,700
Estimated cost per foot	$ 3.37	$ 3.35
Estimated cost, 1951 prices	$7,800,000	$8,000,000

TABLE 2. Comparison of operating costs reclaimed pipe vs. new line.

(Estimate based on 8 in. line 375 miles in length)

	Reclaimed pipe	New line
Number of stations	8	5
Capacity, barrels per day	30,000	30,000
barrels per year	10,950,000	10,950,000
Estimated operating costs per year		
Personnel	$ 393,000	$ 313,000
Power	314,000	304,000
Maintenance	42,000	33,000
Corrosion	3,000	3,000
Vehicles and other work equipment	8,000	8,000
Supplies	24,000	15,000
General administrative expense	45,000	45,000
Interest at 1⅝% average	127,000	130,000
Miscellaneous taxes at 1½%	117,000	120,000
Total operating cost per year	$1,073,000	$ 971,000
Depreciation at 5%	390,000	400,000
Total operating cost including depreciation	$1,463,000	$1,371,000
Transportation tax	200,000	200,000
Total operating cost including depreciation and transportation tax	$1,663,000	$1,571,000
Cost per barrel—mile		
Before depreciation	$0.000262	$0.000237
Including depreciation and transportation tax	$0.000407	$0.000383

Converting in Place

Preparation. As in the case of a line being prepared for take-up, the conversion of a line from crude to petroleum products in place requires the displacement of the oil by water. The same general preparations described in preparing for take-up of a line are necessary when converting in place. After having run the necessary scrapers and having displaced the crude oil, it is then necessary to isolate the line by cutting it out of existing manifolds and crude pump stations. The lines should be pressure tested with water after alterations and changes have been completed.

It was found impractical to attempt to carry this test above 900 psi, as most of the reclaimed pipe utilized was taken from lines laid prior to 1926. Most of the pipe laid at this time was lapweld pipe. After reaching a pressure of 900 psi, fatigue stresses in the old lapweld seams were apparent. It was found that the pipe would not hold this pressure for any length of time. On the line that was constructed between Chicago and Toledo, it was impossible to get the line to hold above 850 psi. When this line was placed into operation, a maximum operating pressure of 800 psi was established. Automatic controls and safety devices were set to control at 800 psi and shut the pump stations down if the pressure exceeded 820 psi. This line has been operating satisfactorily on this basis for approximately 7 years.

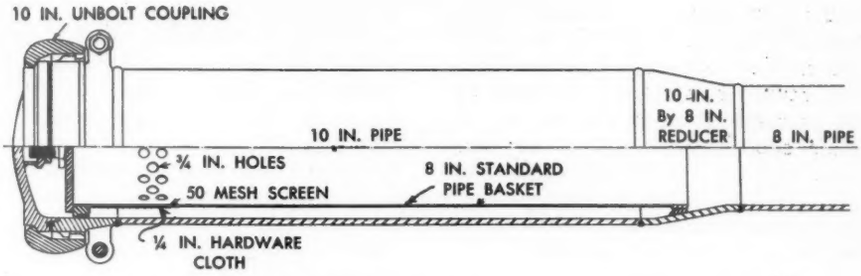
Hydraulic Consideration. In contemplating the use of reclaimed pipe for a products line, it is extremely important to consider the route to be traversed. In an area where mountainous terrain is encountered it would be folly to consider the use of reclaimed lapweld pipe where great static elevation differences exist or where dangerous surges occur. It is an economic necessity to operate a reclaimed line with a very narrow margin of safety factor in order to maintain the highest throughput volume possible.

Present day trends dictate fewer pumping stations, higher pressures, and more automatic equipment; therefore, it is vital to get an accurate profile and the best hydraulic balance possible in the location of pumping stations. Only in this manner can a reclaimed line economically approach the operations possible with a new line.

Limitations. (a) Corrosion problems in converting a line in place to products service:

In all probability the line to be converted will be an old line, uncoated and subject to galvanic and stray current corrosion. To protect a bare line in place from corrosion is a tremendous undertaking. It is infinitely more of a problem if the converted line is one of many bare parallel lines. To cut down on rapidly pyramiding costs due to corrosion leaks, Sinclair within the last few years has undertaken a stop-gap measure of installing sacrificial anodes on a major portion of its extensive crude oil trunk system. This system as shown on the accompanying map consists of many bare parallel lines, one of which has been converted to products service from Shawnee, Oklahoma, to Chicago. The company has maintained accurate leak records for at least the last 15 years, which readily indicate "hot

spot" areas. It is from these records and information derived therefrom that locations were selected for anode installations through known corrosive areas. Anodes were placed at a frequency of one anode per line every 50 ft through corrosive areas. This stop-gap program should be completed this year. Anode life of from six to ten years has been estimated from spot checks of soil resistivity on the installations completed. It was necessary to speed this installation because corrosion costs had reached the appalling figure of $1,500,000 per year. This estimated cost is based on a total of over 3000 leaks in the year 1949, or more than 8 leaks per day, costing approximately $500 per leak. It is hoped this tremendous cost can be cut very substantially showing a quick return on the investment of the anodes installed. In order to return the investment in anodes, a reduction of only 500 leaks per year for a period of two years is required to pay for the cost of the anodes installed on a rush basis. During the year of 1950 in which a large percentage of the anodes were installed, a substantial reduction of 400 leaks was affected. The results should be even more encouraging in successive years for the estimated life of the anodes.



Cut-away view showing Sinclair scraper trap strainer.

(b) Collars and collar leaks:

Old screw joint lines when placed in products service can be expected to develop collar leaks. Collars that long ago leaked small amounts of crude oil, but which were sealed off due to wax deposits, undoubtedly will again start leaking because of the solvent action of the gasoline, kerosine, and other products transported. Product losses may not be excessive through these leaks but the maintenance and repair problem is gigantic. The collars must be caulked as well as possible and then must be welded on both sides. It will be difficult to obtain a satisfactory weld without pin holes due to the gases formed by seeping products.

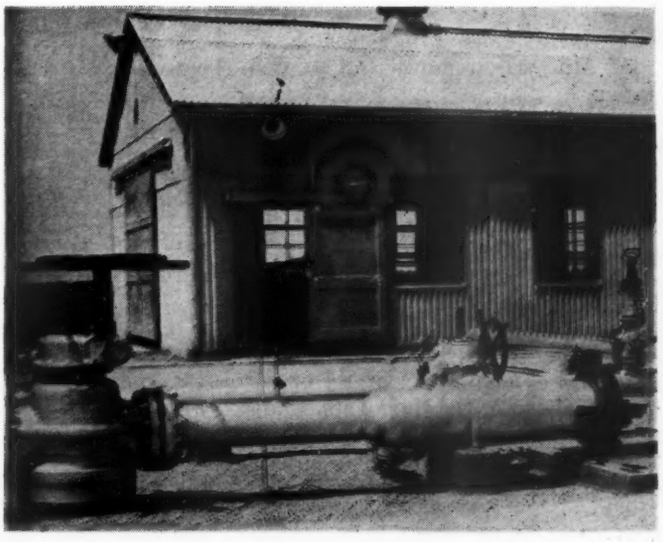
(c) Specifications in cleaning the interior of a crude line:

1. Scrapers, water, and solvents.

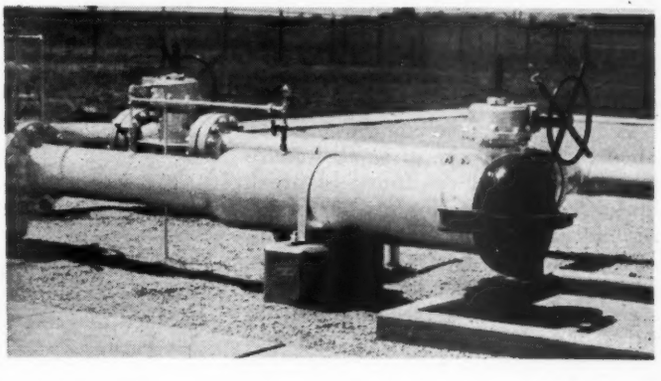
After running quantities of scrapers in the crude oil and displacing the crude oil with water, the problem still remains of removing the adhering wax, "B.S." and other deposits collected during the years the line was in crude oil service.

It has been Sinclair's practice to displace the water with a tender of approximately 25,000 bbl of kerosine. Kerosine has been found to be an excellent solvent for the deposits remaining in the line. The contaminated kerosine can be re-run in the nearest refinery at a nominal cost. The Sinclair products pipe line system is integrated with its refineries, which enables the movement of the contami-

Piping with large strainers removed and replaced by Sinclair horizontal strainer doubling as a scraper trap.



Another view showing installation of Sinclair horizontal scraper trap-strainer.



Scraper trap strainer with internal basket removed.

nated first tender of products to the nearest refinery. Following the initial tender of solvent, only those products that cannot be seriously damaged by an increase in gum content or off color specifications should be handled. At least 100,000 bbl of No. 2 or No. 3 fuel oil should be handled after the initial kerosine tender before attempting to run any gasoline.

2. Problems of color.

It has been found that water white kerosine, which must meet stringent color specifications, cannot be handled without loss of several points on the color range until at least 2,000,000 bbl of products have passed through the line. Very close records of color loss and quantities of products handled were kept in an attempt to determine when it would be safe to ship high grade water white kerosine. It was found in running these tests and analyzing samples that not only was the residue of hydrocarbons to be blamed for the color damage but also very fine rust and mill scale, which had been formed in crude operation, was responsible for a large amount of the color damage. After the film of wax had been dissolved and mill scale and existing rust had been removed, it was quite apparent that the addition of Sinclair RD 119 internal corrosion inhibitor assisted materially in clearing up any further internal corrosion of the line.

3. Mill scale removal and strainer design.

After a period of operation during which the wax film was removed, the original mill scale and some apparent corrosion products that had been formed during the early part of the crude operation were collected in strainers at each pumping station. In fact, for a period of a few months, the problem of scale removal was so serious that scrapers became stuck behind masses of mill scale and corrosion products in the line. This condition cleared up in a matter of two or three months after products operations began. Sinclair's inhibitor RD 119 has effectively eliminated further internal corrosion problems to the extent that elaborate strainers placed in the pump stations to catch this mill scale could be removed and salvaged for future installations.

The inhibitor is effective not only throughout the pipe line system but protects consumers equipment as well.

A new type of strainer was developed that takes care of small quantities of scale that continued to break loose from the interior surface of the pipe in diminishing quantities. A cutaway view of this strainer is shown. This type of strainer has enabled Sinclair to eliminate a large quantity of valves previously required and has streamlined the appearance of the piping layout. Pictures of the pump station piping before and after the removal of these strainers illustrate the point. The new type strainer is placed in the scraper trap, which can be opened by means of a unibolt coupling, and the strainer can be removed and replaced in a matter of a few minutes. The strainer has been designed so that in the event a scraper is being run it can pass into the inside of the strainer basket with ease and can be removed with the scraper basket.

(d) Economics of converting a line in place:

The tabulation given in Tables 3 and 4 shows the economics of converting a crude line to products service in place without removal for reconditioning. The only reconditioning that must be performed is in repair of leaks that occur during water pressure tests. It was extremely fortunate that in a number of cases Sinclair had existing crude lines traversing a route along which a products line was proposed. By converting the line in place, it will be seen from the tabulation that the tremendous cost of take-up and reconditioning as well as relaying of a line was eliminated. The transfer in this case was merely a book transaction with incidental costs in addition to pump station costs.

Present Day Trends

Large crude lines. (a) Release of smaller lines for products use:

Present day trends in the construction of crude oil pipe lines has been toward larger diameter crude oil lines, which can be economically operated effecting a great saving in transportation costs. In the construction of these large diameter lines there is the general trend to abandon or reclaim previously constructed smaller lines. Due to the shortage of steel, numerous companies will be faced with the necessity of utilizing the smaller crude lines from 6 in. to 12 in. in size for refined products use either by reclaiming the pipe or by converting the line in place. Although the trend in products operation is always moving toward higher pressures and more

TABLE 3. Actual cost of reconditioning old pipe line vs estimated cost of new line.

(Estimate based on 8 in. line) 1947 prices

Assumptions	Reconditioned line	New line
Length of line	375 miles	375 miles
Throughput capacity—daily—(gasoline)	30,000 BPD	30,000 BPD
Pumping stations	8 at 800 psi	5 at 1280 psi
Pipe wall thickness	0.322 in.	0.250 in.
Construction costs		
1. Cost of displacing oil, pressure testing, replacing or repairing defective pipe	$ 337,000	$.....
2. Damages (old line)	80,000	.....
3. Rights-of-way and damage (new line)	.....	600,000
4. Pipe (book value of old line)	260,000	1,980,000
5. Casing, vents and markers	.....	80,000
6. Freight	.....	450,000
7. Installation cost (line pipe)	.....	1,750,000
8. Protective coating	.....	360,000
9. Cathodic protection	750,000	30,000
10. Tank lines and manifolds	50,000	50,000
11. Pumping stations	960,000	600,000
12. Tanks	250,000	250,000
13. Real estate	37,000	25,000
14. Communication system	250,000	250,000
15. Vehicles and work equipment	40,000	20,000
16. Supervision and engineering	200,000	200,000
Total estimated cost	$3,214,000	$6,645,000
Estimated cost per mile	$ 8,560	$ 17,700
Estimated cost per foot	$ 1.63	$ 3.35
Estimated cost, 1951 prices	$3,800,000	$8,000,000

TABLE 4. Comparison of operating costs reconditioned pipe line vs new line.

(Estimate based on 8 in. line 375 miles in length)

	Reconditioned line	New line
Number of stations	8	5
Capacity, barrels per day	30,000	30,000
barrels per year	10,950,000	10,950,000
Estimated operating costs per year		
Personnel	$ 443,000	313,000
Power	314,000	304,000
Maintenance	100,000	33,000
Corrosion	37,000	3,000
Vehicles and other work equipment	16,000	8,000
Supplies	24,000	15,000
General administrative expense	55,000	45,000
Interest at 1⅝% average	62,000	130,000
Miscellaneous taxes	117,000	120,000
Total operating cost per year	$1,168,000	$ 971,000
Depreciation at 5%	190,000	400,000
Total operating cost including depreciation	$1,358,000	$1,371,000
Transportation tax	200,000	200,000
Total operating cost including depreciation and transportation tax	$1,558,000	$1,571,000
Cost per barrel—mile		
Before depreciation	$0.000285	$0.000237
Including depreciation and transportation tax	$0.000380	$0.000353

cooperative ventures, most companies will be faced as Sinclair has been during and immediately following the last war with the decision either to defer their plans until steel for new high pressure lines can be made available or plunge into a program of products pipe line construction with reclaimed pipe. The tabulation in Table 5 is an attempt to theorize on the economics of building a pipe line immediately from available reclaimed steel or waiting a period of several years until new pipe can be made available. The time gained in moving into a new marketing area, becoming firmly entrenched, and enjoying freight savings must be carefully weighed in comparison to absorbing high transportation costs and waiting until new steel is available.

Steel efficiency new pipe vs old pipe. The tabulation in Table 6 is an attempt to evaluate the total steel efficiency of a reclaimed or converted pipe line as compared with one constructed with new high tensile steel. It will be seen from this tabulation that new high tensile steels either electric weld or seamless will allow a trend toward lighter weight pipe provided it is adequately protected with a cathodic protection program.

TABLE 5. Savings to be effected by building reclaimed line or converting vs waiting for new steel.

	New line	Reclaimed line	Converted line
Construction costs	$8,000,000/yr.	$7,800,000/yr.	$3,800,000/yr.
Out-of-pocket operating costs	$ 971,000	$1,073,000	$1,168,000

Estimated freight savings

Rail or truck movement	375 miles	$1.00/bbl
Pipe line tariff	375 miles	37.5c/bbl
Estimated savings		62.5c/bbl

Volume, BPD	Savings Per day	Per month	Per year
30,000	$18,750	$562,500	$6,750,000
20,000	12,500	375,000	4,500,000
15,000	9,375	281,250	3,375,000

In ten years the difference in operating costs would amount to $1,000,000 between the new line and the reclaimed line. The difference between the new line and the line converted in place would be approximately $2,000,000. Assuming the time gained in not waiting for new steel to be two years, the savings in freight as shown in the above tabulation will completely offset the higher operating costs of a 10 year period in approximately two months and four months, respectively, on the reclaimed and converted lines based on a maximum capacity of 30,000 barrels per day.

TABLE 6. Steel efficiency of new vs old pipe.

Grade X-42 line pipe

Size line, in.	Wall thickness, in.	Tons per mile	Min. yield strength, psi	Ultimate bursting strength, psi	Safety factor*
8⅝ (old pipe)	0.322	75.37	850	850	1.06 at 800 psi
8⅝ (new)	0.250	59.03	2435	3479	1.90 at 1280 psi
8⅝ (new)	0.188	44.62	1831	2616	1.43 at 1280 psi

* Safety factor based on minimum yield strength.

In cold rolling operations such as used on electric weld pipe, it can be safely assumed that X-42 plate gains tensile strength both in transverse and longitudinal section. It is reasonable to assume then that X-42 plate becomes X-46 minimum pipe through cold working of the steel. Based on this assumption the new safety factors would be as follows:

Grade X-46 pipe

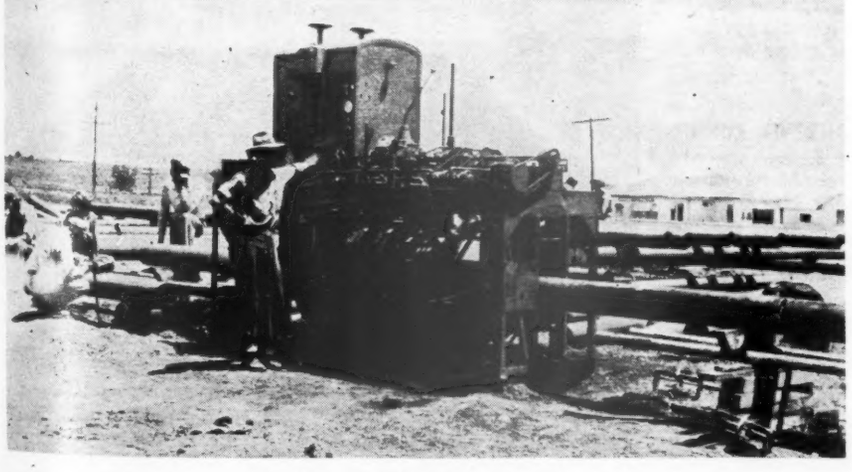
		Safety factor
8⅝ in. OD	0.250 in. wall	2.075 at 1280 psi
8⅝ in. OD	0.188 in. wall	1.56 at 1280 psi

Saving in tons for 375-mile line (0.250 in. wall) = 6,127 tons = $ 765,875
Saving in tons for 375-mile line (0.188 in. wall) = 11,531 tons = $1,441,375

Summary

From the foregoing record of Sinclair's experience in converting and reclaiming crude oil lines for products service, it can be seen that a number of problems are involved. The major consideration is of course the economics of the venture. The reclaimed and converted lines will not allow high pressure operations, therefore, require a greater number of pump stations with the accompanying high investments, greater power costs, and a greater requirement for man power. The problem of cleaning out deposits remaining in crude lines is serious. It is necessary to transport large volumes of refined products before the last traces of this contamination have disappeared. The problem of maintaining specifications of products under these conditions is difficult and management must be cognizant of this problem.

In reviewing operations, greater maintenance and repair costs will be found on converted products pipe lines. The future policy of most major companies in considering the use of larger crude oil lines will be influenced by the fact that they will release smaller lines, which in turn can be reconditioned for use in products service. The economy of operation is necessarily in favor of new steel and high pressure operation; however, companies faced with large quantities of reclaimed pipe must weigh the cost of abandoning these lines against their use in products service compared to the purchase of new steel. The effect of the present emergency, should it become aggravated, will no doubt have a great bearing on the future consideration by all companies of the utilization of old crude lines for refined products use.



Sinclair yard cleaning machine.

Recommendations

Concerning lapweld screw joint lines. It is Sinclair's recommendation that if it is necessary to use a line that was constructed in the era of screw joint construction, that great care be exercised in welding the collars of such a line and that operating pressures be held substantially below water test pressures.

Concerning welded lines. If the line to be converted is of welded construction, the problems will be infinitely fewer than those encountered with a screw joint line. The cleaning operations will be much easier. There will be far fewer voids that have been filled with waxey hydrocarbon components. If such a line is available for conversion to products use, there should be no hesitation in converting it. * * *

HOW TO BE SURE YOU GET . . .

THE RIGHT GEAR UNIT FOR YOUR HIGH-SPEED DRIVE

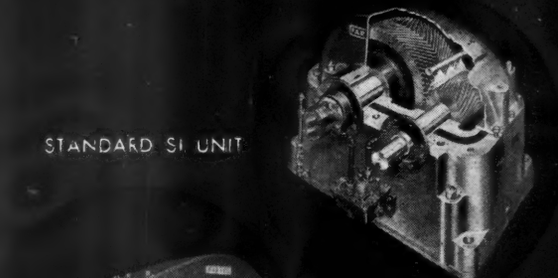
The extremely high peripheral speeds encountered in speed increasing and high-speed reducing applications present difficult problems in design and construction. These can be answered only by the kind of specialized engineering skill, manufacturing facilities and experience found at the Buffalo plant of Farrel-Birmingham.

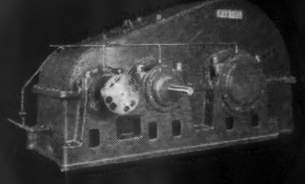
SPEED INCREASING UNITS—Farrel Type SI units were the first speed increasers to be developed in a standard series for pipe line pumping service. That was eighteen years ago, and all of the original units, as well as those installed since, are still in operation.

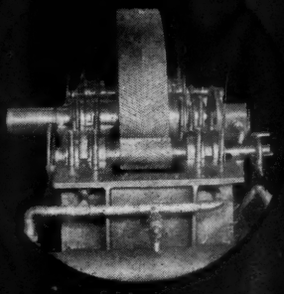
The modern SI line consists of 49 standard sizes with speed ratios ranging from 1:1 to 12:1. For higher ratios, units using two sets of gears are supplied with ratio range from 12:1 to 40:1. Two-pinion units, designed to transmit power from a single engine to two pumps, are also available.

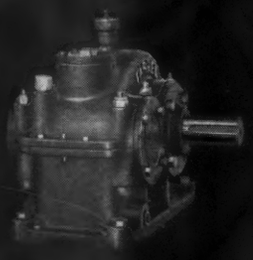
SEMI-HIGH SPEED UNITS—When requirements fall between the range of Type SI units and standard commercial speed reducers, Farrel semi-high speed units are recommended. These units are designed for pinion speeds up to 3600 RPM and gear pitch line velocities up to 4000 FPM.

Farrel engineers will be glad to help you select the right gear unit for your high-speed application. Write for further information about any of the types mentioned.


STANDARD SI UNIT


DOUBLE STEP-UP UNIT


TWO PINION UNIT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PIPE LINE MOVEMENT OF LPG†

Increasingly larger volumes of LPG will be moved through pipe lines in future — What are the techniques and problems involved?

D. A. ROACH*

LIQUEFIED petroleum gas, i.e. butane and propane, might well be termed the orphan of the pipe line industry. Until quite recent years, these important products were not considered as separate and distinct commodities for transportation by either the crude oil or products pipe line industry.

Propane and butane are frequently handled through pipe lines by blending small percentages with crude oil or natural gasolines. Butane of course is often moved by blending into motor fuel or motor fuel components. In this paper we desire to outline the handling of butane and propane as finished products where attempts are made to preserve their original specification while moving from point of manufacture to final destination.

Butane and propane are unique products to the pipe line industry for several reasons.

1. Unlike gasoline or distillates, they require moderate pressure to liquefy. At 100 F, propane has a vapor pressure of approximately 190 psi. At the same temperature, N-butane has a vapor pressure of approximately 55 psi.

2. Both products require expensive pressure storage, which is usually constructed in multiple, small capacity, units.

3. Both products are of low specific gravity. Propane has a specific gravity of about 0.51 and n-butane a specific gravity of 0.58.

4. Both products are highly compressible. At 60 F, 1000 psi pressure change will compress butane about 2 per cent and propane about 3.8 per cent. This compares with compressibility of about 0.8 per cent for gasoline and 0.6 per cent for kerosine.

5. Specifications for most uses require a product of high purity.

6. Present demand for LPG is seasonal and subject to considerable seasonal variations. This fact coupled with the high cost of LPG storage is an important economic consideration in handling LPG by pipe line.

LPG is a product of refinery, natural gasoline plant, and cycling plant operation. The uses for these products have expanded rapidly and now include domestic heating, gas manufacture, chemical manufacture, and fuel for internal combustion engines. Table 1 shows the size of this pipe line "orphan" for the years 1930, 1940, and 1950. These figures do not include LPG used for motor fuel blending nor do they include sales of hydrocarbons to plants manufacturing synthetic rubber, aviation gasoline, or their components.

No accurate data is available on the volumes of LPG that are being transported at the present time by products pipe lines. It is believed safe to assume that less than 10 per cent of the total volume marketed is being transported by products pipe lines. Despite tremendous growth of the LPG industry, the total volume is still relatively small in pipe line terms when compared with present volumes of gasolines and distillates transported by products pipe lines.

It is beyond the scope of this paper to present a detailed forecast of the future volumes of LPG that will be available for pipe line transportation. A recent study by R. C. Alden of Phillips Petroleum Company presents some interesting facts in this regard.

"The extent of our present natural gas reserves and the anticipated high rate of discovery in the coming decade makes the recovery and utilization of liquids extracted from natural gas a matter of major concern to the petroleum industry.

"Analysis of the various uses for motor fuel leads to the conclusion that the full potential domestic commercial motor fuel market (truck and

†Presented before the American Petroleum Institute, Products Pipe Line Technology Conference, Atlanta, Georgia, May 21-23, 1951, under the full title, "Pipe Line Transportation, Storage, and Shipment of Liquefied Petroleum Gas."

*Products pipe line department, Phillips Petroleum Company.

FIG. 1. Marketed production of LPG.

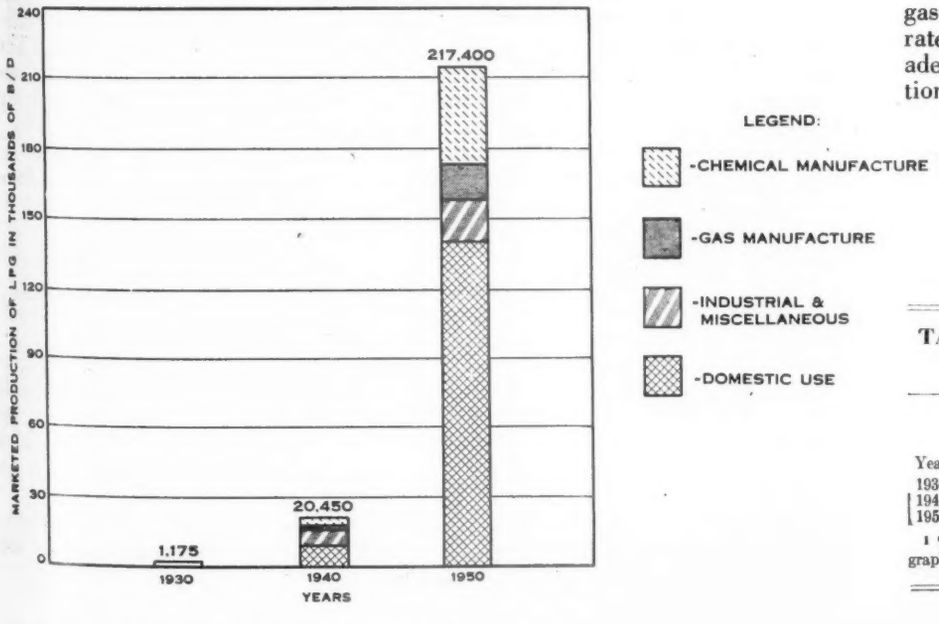


TABLE 1.[1] Marketed production of LPG in barrels per day.

Year	Domestic	Industrial and miscellaneous	Gas manufacture	Chemical manufacture	Total
1930	770	145	260	.....	1,175
1940	8,750	8,120	1,320	2,260	20,450
1950	139,780	19,570	15,650	42,400	217,400

[1] The information contained in Table 1 is also shown graphically in Fig. 1.

bus, and tractor and other non-highway uses) would require a supply of liquefied petroleum gas equal to nearly 45 per cent of motor fuel production. Capture by LPG in the next 10 years of half this market would provide an increment of motor fuel equivalent to approximately 20 per cent of total motor fuel production. This would be of paramount usefulness in cushioning the civilian economy against the military requirements for gasoline in wartime."[2]

Fig. 2 represents an estimate of the LPG and motor fuel producible from our reserves of crude oil, natural gas liquids, and natural gas. It is startling to realize that the LPG potential of our petroleum reserves may soon equal the potential for motor fuel. Thus it is a very distinct possibility that products pipe lines will handle increasingly larger volumes of LPG in the years to come.

Phillips Petroleum Company has been handling butane as a finished product for some 20 years in its Borger, Texas-East Chicago, Indiana, products pipe line. Approximately 1,500,000 bbl of butane were handled during the year 1950. Propane has been transported regularly in the Borger, Texas-Denver, Colorado, line since 1947. In 1950 approximately 550,000 bbl of propane were handled in this line. This volume constituted about 22 per cent of the product handled by this line.

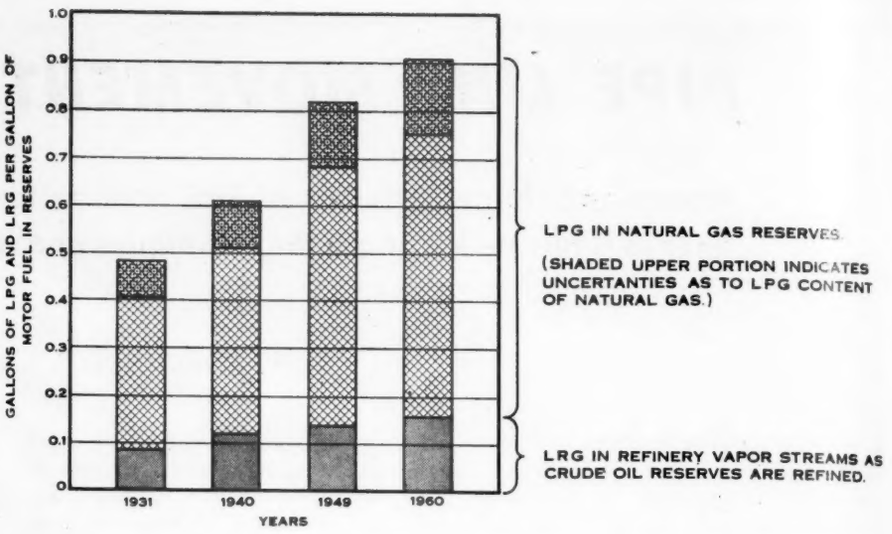


FIG. 2. Total potential LPG in natural gas reserves and LRG from crude oil reserves relative to motor fuel in reserves.

Tankage

The major expenditure required for pipe line handling of LPG is that of tankage. Phillips' pipe line tankage for LPG is usually constructed to conform to local, state, and national codes. Most of our butane tankage is 75 psi test pressure. Some of this storage is 12 by 42—1000 bbl vertical tanks arranged in batteries of five. These tanks were shop fabricated. Also in use are 30 by 70 vertical tanks of riveted construction and 7500-bbl capacity. Newer butane tankage consists of 12,000-bbl blimps of welded construction.

Our propane tankage is usually 9 by 63 horizontal tanks of approximately 600-bbl capacity. Newer tankage consists of 12 ft by 92 ft horizontal tanks of 1600-bbl capacity. It can be seen from this that the trend is definitely toward larger vessels for LPG storage. In spite of this improvement, butane tankage costs approximately $10 to $12 per bbl and propane tankage from $14 to $17 per bbl. Furthermore, the maximum size of steel containers is limited by materials construction techniques, and costs.

If low cost, large volume storage at both manufacturing and consuming locations are possible, a major obstacle in low cost pipe line transportation of LPG will be overcome. Underground storage in mines, wells, and the like, is currently being considered by several organizations.

The high costs of LPG tankage indicate that the frequent pumping of small slugs is an economic necessity. This is somewhat undesirable of course as the pumping of small slugs increases the overall percentage of contamination. The construction of expensive LPG storage to care for peak demands may not always be justified. One possibility is to construct more low pressure storage and give LPG products priority during their peak demand periods. There is also the alternative of handling a constant volume of LPG by pipe line and using other transportation to meet peak requirements.

Measurement

Measuring LPG receipts and deliveries is an important part of LPG pipe line handling. Numerous types of gauges including sight glasses, slip tubes, float type ground reading gages, magnetic gages, and rotary gages are in use. Any of these gages are liquid level devices and do not measure the volume of liquid contained in the tank vapors. This volume may run as high as several per cent depending on the temperature. Tank tables are often used that include the equivalent liquid volume of these vapors.

We prefer to measure pipe line receipts and deliveries by positive displacement meters. Pressure prover tanks are not used to prove these meters on LPG. The meter factor is obtained by multiplying the previous factor determined for base gasoline by 1.0146. This ratio was determined by a series of tests on 30,000-gal storage tanks. It is subject to some errors but it is convenient and provides a more accurate measurement than gaging.

Testing

LPG, like other pipe line products, is tested before accepting for shipment. The most common tests made are:

(1) Gravity measurement.
(2) Weathering and oil stain test.
(3) Dryness test.
(4) Vapor pressure test.

Gravities are measured by using a pressure hydrometer jar. The weathering test evaporates a 1000-cc sample and indicates the presence of residue (gasoline or oil) in the product. The oil stain test indicates whether this residue is a gasoline or oil. The dryness test is made by passing product vapors through cobalt bromide. A color change indicates moisture in the product. Vapor pressures are determined by use of a pressure bomb. The dryness and vapor pressure tests are not customarily made when receiving product for shipment.

Product buffer slugs are used on both butane and propane. A butane slug in the Borger-Chicago line is buffered as follows:

1. Natural gasoline.
2. Butane—25,000 to 45,000 bbl.
3. Natural gasoline.

Normally the butane-natural mixture is not a contaminate and is blended into motor fuel. Fractionation facilities are available at Chicago and these butane-natural mixtures may be fractionated if required.

Propane shipments on our Borger, Texas-Denver, Colorado, 6-in. line are buffered as follows:

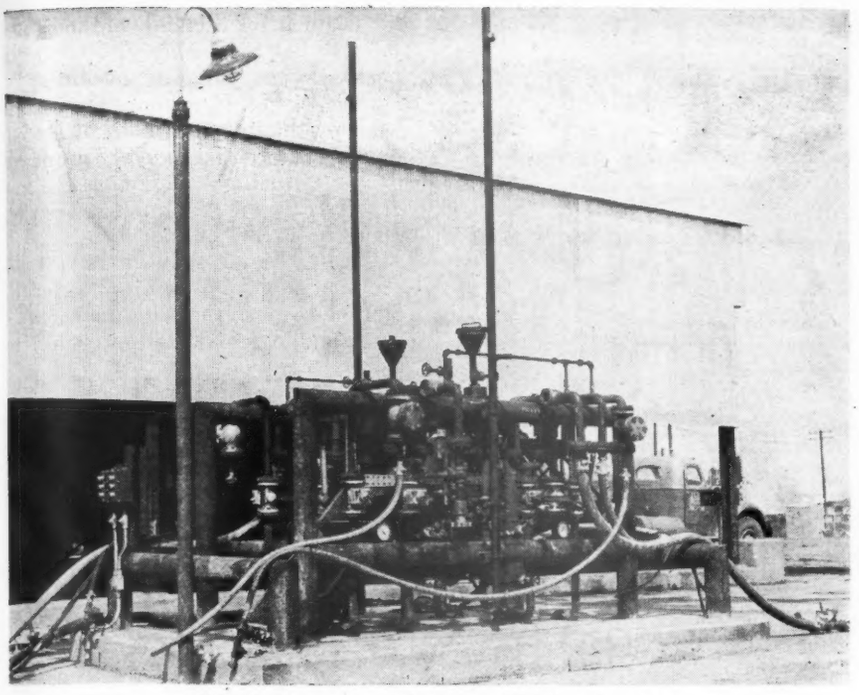
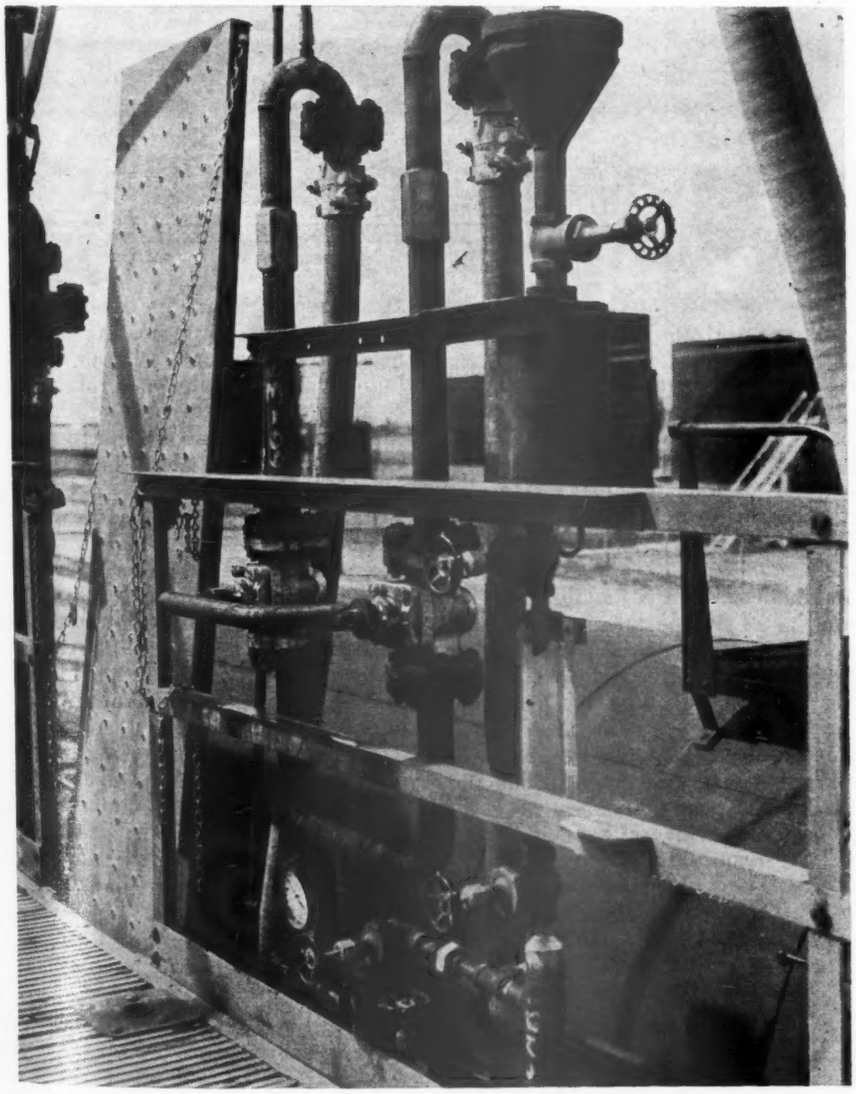


FIG. 3. Denver terminal for loading trucks.

FIG. 4. Typical stench pot.



1. Housebrand gasoline.
2. Butane buffer—200 bbl.
3. Propane slug—7500 bbl.
4. Butane buffer—100 bbl.
5. Housebrand gasoline.

On this line, the small volume of gasoline-butane mixtures are disposed of in housebrand gasolines. The butane-propane mixture is marketed as such. No fractionation facilities are in use on this line. On both pipe lines, it is the practice to take heart-cuts of LPG products at intermediate terminals.

Loading

LPG is loaded at our terminals to both tank car and truck. Product is tested in tankage before loading occurs. Loading pumps are of the deep well centrifugal type. This type of pump eliminates "gassing up" or "vapor locking" and permits storage tanks to be erected on lower foundations. Loading systems utilize both a liquid line and a vapor return line. LPG is not metered when loading. A typical truck loading spot is shown in Fig. 3. All liquid lines at loading docks contain an excess flow valve immediately upstream from the hose connection. Similar piping is used on tank car loading spots. The majority of LPG product is stenched with mercaptan or cal-odorant during the loading process. Fig. 4 shows the type of stench equipment commonly used. We believe there is a great deal of room for improvement on this apparatus. Slip tube gages are usually used to measure the product loaded to tank cars. Rotary gages are in common use on LPG tank trucks. LPG loading is a much slower operation than loading conventional products. This is due to increased connection time, slower loading rates, and the necessity of close supervision by the loader.

Pumping Equipment

No special main line pumping equipment is used to handle LPG. On our Borger-Denver line we are using variable stroke triplex pumps with conventional packing. A force-feed lubricator injects small quantities of lubricating oil into the packing. Commercial glycerine was originally tried as a packing lubricant. Lubricating oil is now used and gives equal results at a lower cost.

Our Borger-Chicago line handling butane uses 3-and 4-stage centrifugal pumps with conventional packing. Stuffingbox pressures on these pumps run as high as 1000 psi. Packing on these pumps is also lubricated by a force-feed lubricator as shown in Fig. 5. Good results have been obtained with this lubrication from the standpoint of leakage prevention, packing

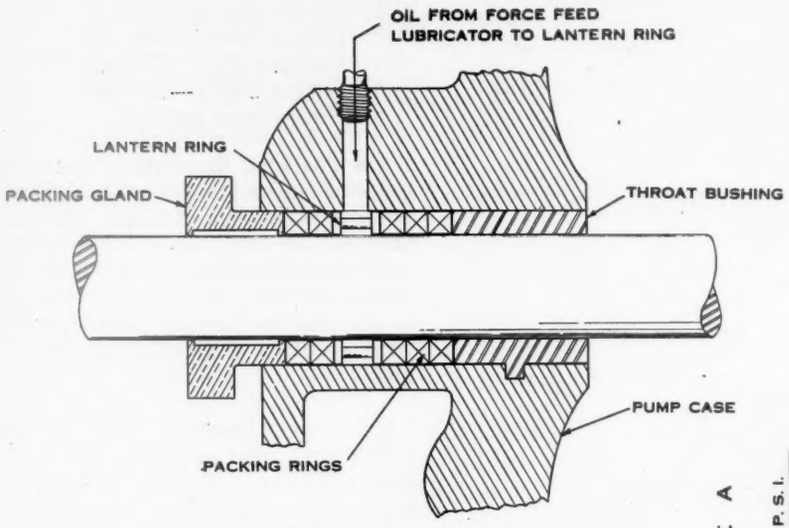


FIG. 5. Method of packing lubrication on main line pumps.

wear, and packing replacement. It should be pointed out that the quantity of lubricant injected is not great enough to affect the specification of the LPG.

Several points are of interest in connection with the hydraulics of LPG handling. As previously mentioned, LPG requires moderate pressures to keep it in a liquid phase for pipe line pumping. This requires high station intake pressures and resultant loss of capacity.

Propane and butane have specific gravities of 0.51 and 0.58, respectively, in comparison with gasoline gravities of about 0.74 and distillate gravities of about 0.82. These low gravities greatly reduce the differential pressure produced by centrifugal pumps having constant speed, electric motor drives. This is illustrated in Table 2, which assumes a 1000-hp motor loaded to 1050 hp on 0.82 specific gravity

TABLE 2. Differential heads developed by centrifugal pump at constant speed.

Product	Specific gravity	Motor hp	Differential head in ft	Differential head in psi
Propane.....	0.51	653	2780	615
Butane.....	0.58	743	2780	700
Gasoline.....	0.74	947	2780	890
Kerosine....	0.82	1050	2780	985

TABLE 3. Pressure drop in psi per mile for various products computed by T. R. Aude formula.

Product	Specific gravity	Absolute viscosity in centipoise at 60 F	Calculated pressure drop in psi/mile
Propane.....	0.51	0.12	8.9 psi
Butane.....	0.58	0.18	9.3 psi
Gasoline.....	0.74	0.83	14.9 psi
Kerosine....	0.82	2.50	20.1 psi

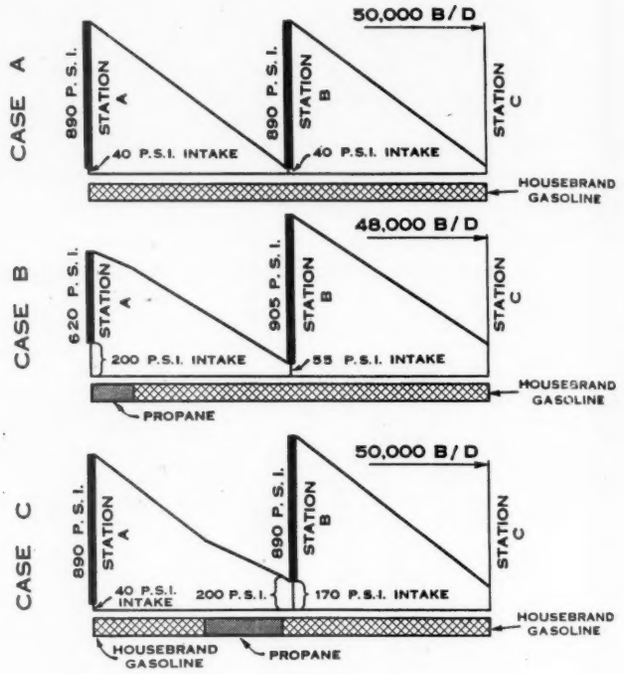


FIG. 6. Pipe line hydraulic gradients.

lic gradient for this line and indicates the line has a capacity of 50,000 bbl per day when pumping gasoline.

Case B, Fig. 6, assumes propane is entering the line at Station A. Due to the low differential pressure produced by the centrifugal pumps on the low gravity propane, the rate has been reduced to 48,000 bbl per day.

Case C, Fig. 6, shows a 12,000 bbl propane slug approaching Station B. Station B must raise its intake pressure as the propane approaches to distillate at a rate of 50,000 bbl per day.

On the plus side of the hydraulic picture is the favorable friction characteristics of LPG products. Table 3 shows the pressure drop in psi per mile for various products using the T. R. Aude formula and assuming a 50,000 bbl per day rate and 10.25 ID line.

The effect of LPG handling on the capacity of a pipe line is dependent on a good many factors. These factors include topography, station spacing, slug length, and type of pumping equipment. In some systems an actual increase in gross barrels per day will result. In some systems a sizable reduction in capacity will result.

Fig. 6 shows several different cases of LPG handling in a hypothetical pipe line. This pipe line is assumed to be a 10.25-in. ID line with 59-mile station spacing. Pumping units are assumed to be centrifugal pumps with electric motor drives. Buffer slugs have been omitted to simplify the illustrations.

Case A, Fig. 6, is a typical hydraumaintain sufficient pressure at the head of the propane to keep it in a liquid state. The calculated rate at this condition is 50,000 bbl per day. A rate in excess of 50,000 bbl per day could be reached when the propane was closer to Station A.

As previously mentioned the problem of capacities when handling LPG is a problem that must be solved for each individual system.

Pipe line transportation of LPG is probably in its infancy. There is a great deal of room for improvements in some equipment and handling techniques. We believe that LPG may be transported successfully in products pipe lines with other products. It is predicted that the "LPG Orphan" will soon be a full-sized brother in the regular line-up of products transported by the products pipe line industry.

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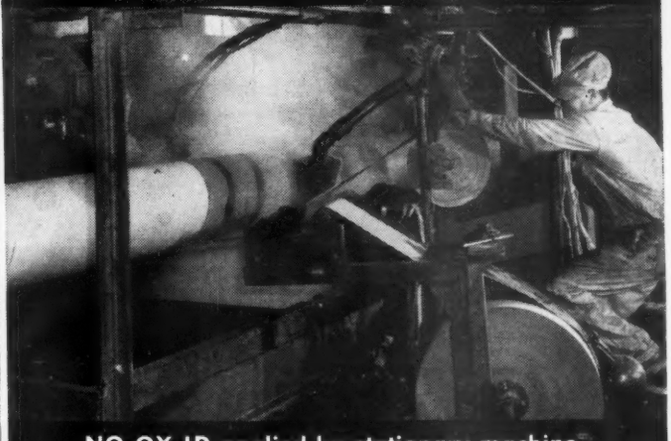
1. Rugh, K. W., and Benz, G. R., "Special Report on LPG Growth," *Oil and Gas Journal*, Vol. 50, No. 1, pp 28-29 (January 4, 1951).
2. Alden, R. C., "The Availability of LPG for Direct Motor Fuel Use," *Petroleum Processing*, Vol. 5, 1180-6, No. 11 (November 1950).

* * *

NO-OX-ID cold applied by hand

NO-OX-ID hot applied with granny rag

NO-OX-ID applied by traveliner



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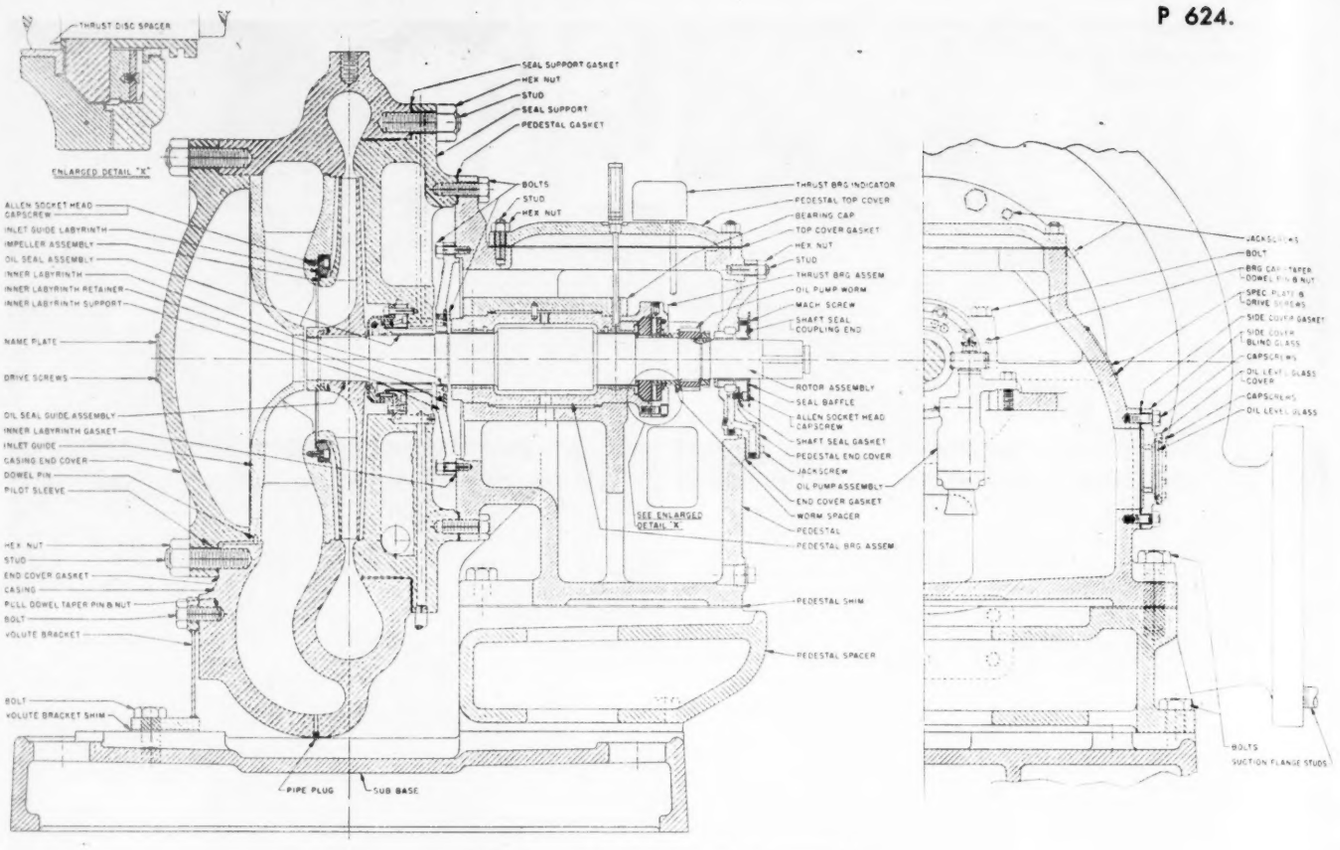


FIG. 1. Main cross-section assembly.

THE POSITION OF

Turbo-Machinery in the Gas Industry†

T. P. LATIMER*

THE axial, centrifugal, and reciprocating compressors are individually suited to particular ranges of flow and pressure. In general, the efficient operational area of each compressor type is separate and distinct from the other. The large flows and low pressures are associated with an axial while the small volumes and high pressures are a feature of reciprocating machinery. The centrifugal compressor is in between. It follows from this that one machine will never replace the others. Each type, due to its different pressure-flow characteristic, must be evaluated for an application in terms of the desired conditions.

Some instances, such as an inlet flow of 100,000 cfm preclude the use of reciprocating machinery. Equally true is the use of an axial compressor for 1000 cfm. A clear distinction in application is, however, the exception rather than the rule. A definite overlapping of the range of operation between the reciprocating and centrifugal compressor is present. Similarly the axial compressor and the centrifugal compressor may be used under certain conditions.

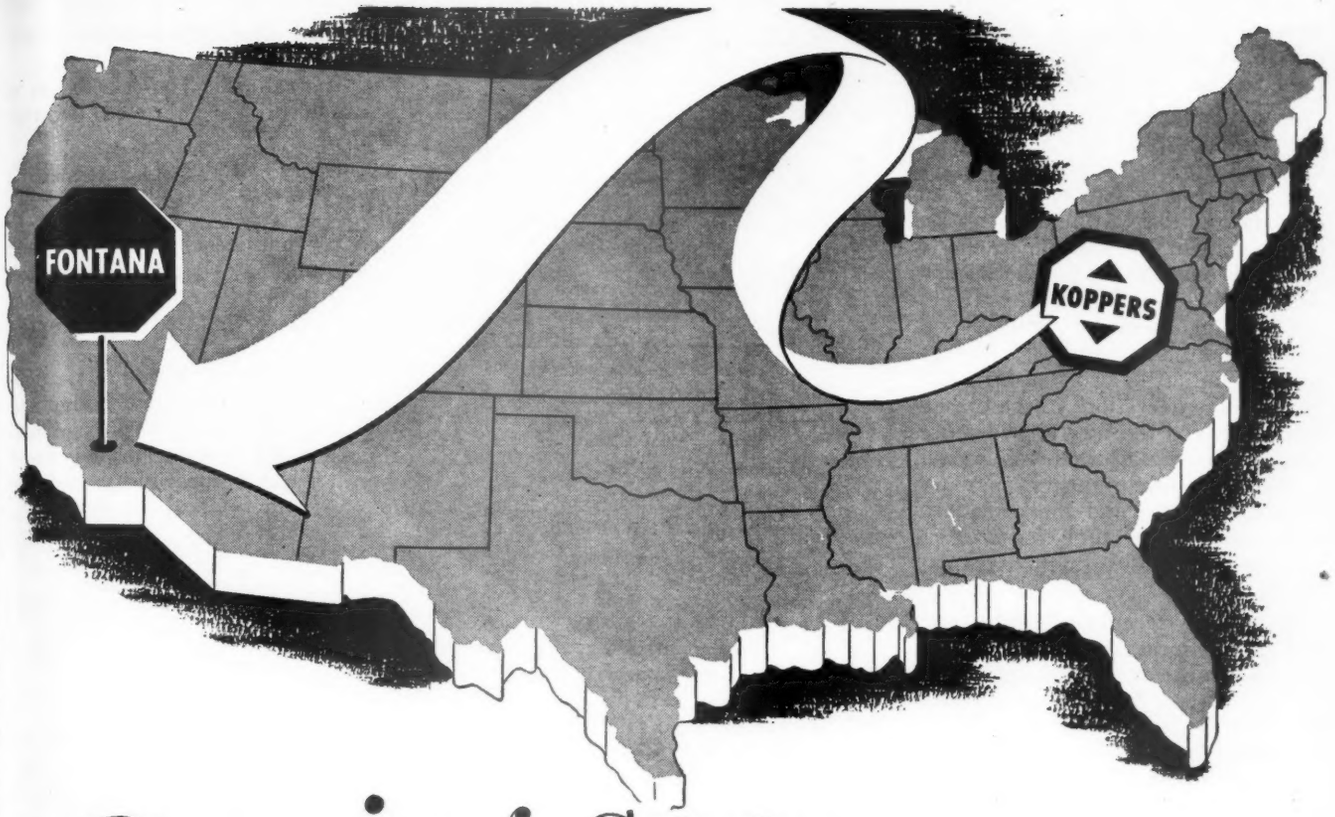
The rapid expansion in the last decade of industries requiring high capacity compression equipment has focused attention on turbo-machinery, a relative newcomer in the oil and gas industry. Sufficient units, particularly of the centrifugal type, are now in operation to raise many questions concerning their use. This is true in the area of operation in which both reciprocating and centrifugal compressors are applied.

One of the greatest uses at this time of both types of compressors is the pumping of natural gas through pipe lines.

Due to the basic differences in the characteristics of each compressor, however, a situation that favors one type will not reflect to the other's advantage. Consequently, we will confine further discussion to the application of turbo-machinery and the various types of drivers available, for the com-

†Presented before the Oklahoma State Meeting of the American Institute of Chemical Engineers, Tulsa, October 7, 1950.

*Clark Bros. Co., Inc.



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pressor prime mover is an integral part of a compression problem and the economic equipment selection.

Sound engineering practice dictates the gradual introduction of a new type of machinery to an industry. This phase has been underway for centrifugals during the last few years and has, of course, yet to be undergone by the axial compressor. During this transition period the centrifugal compressor is being applied by various gas transmission companies—less one exception—in one or two stations only.[1] The reliable operation[2] of the present units will lead the way to wider use. Actually all phases of the gas, as well as the petroleum industry, may use turbo-machinery, and the considerations related to the pipe line boosters apply equally well to multi-stage machines.

Despite the recent use[3] of the centrifugal compressor on pipe lines, many years of engineering experience are behind their design. The hydraulic shapes of the parts have evolved from the design and operation of centrifugal pumps over the last years while the principle of overhanging impellers is proved in present turbine practice. As many as six impellers are overhung in a mercury turbine and Clark Bros. Co., Inc., commonly uses this feature with 2, 3, and 4 impellers as large as 32 in. in diameter. Leaving consideration of the driver aside at the moment, the proved use of the high pressure oil seal was the final impetus to the acceptance of turbo-machinery by many major gas transmission companies.

The centrifugal compressor is a simple mechanical design requiring few parts, only one of which rotates. The booster consists of three major components, a housing, a seal, and a bearing assembly as noted in Fig. 1. The gas enters and passes through the first part, a single casting. The casting is used to minimize the leakage that may occur with a horizontally split case. Passageways lead the gas to vanes that guide the gas into the impeller. The gas leaves the impeller through another integral passageway and returns to the line. The impeller is supported by a short, strong shaft that rotates in the precision bearings of the second component. The seal is placed between the two parts at the point the shaft leaves the casting.

The pressure-flow characteristic of the compressor is equally simple. (Fig. 2). A single impeller will develop a pressure ratio in proportion

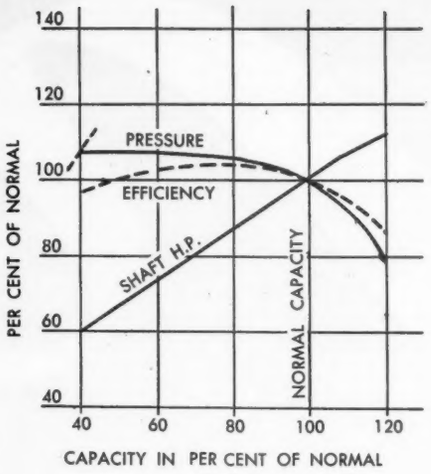

FIG. 2. Performance characteristics.

to the tip speed of the wheel,[4] and once the machine is designed the ratio at constant speed is in accordance with the *inlet flow* alone. This ratio, as well as the efficiency, is essentially constant over the compressors operating range. Any ratio above or below the line may be obtained with speed variation. A fixed speed, resulting from a synchronous or induction motor driver, limits operation along the single line in response to the capacity at the inlet. Operation below the line may be accomplished by throttling or varying the angle of the inlet guide vanes. The former method imposes a fixed loss on the system, which is quite large on trunk lines. The use of movable guide vanes is more efficient, as the power loss associated with throttling is avoided.

The pressure rise in a compressor is obtained in the impeller and the discharge passageway. The machine is designed to procure the greatest portion of the pressure rise in the impeller. This component is the most efficient pressure converting device. It emphasizes the significance of speed variation in obtaining the best operational flexibility.

The low pressure ratio characteristic of the booster is advantageous in minimizing the horsepower requirements of newly designed transmission lines. This is done by the spacing of the compressor stations.

A 30-in. OD pipe line designed for 350,000,000 std. cu ft per day[5] of 0.6 SG natural gas and a station discharge pressure of 850 psia will illustrate this. Consider a 250-mile section of line. The overall ratio is dependent on the number of stations and may be divided among the boosters in several ways.

a. The ratio may be selected so as to use a direct connected two-pole motor.

b. The horsepower may be selected so as to load an existing turbine.

c. A combination of speed and horsepower may be selected in accordance with the desired duty. In other words a driver is fitted to a compressor.

The first two methods impose limitations on the compressor design and their inherent flexibility is diminished. The following example is based upon the latter possibility and the use of four boosters throughout.

Stations	Spacing, miles	Pressure ratio[6] per station	Horsepower
2	250	2.59	16,850
2	125	1.319	10,400
4	62	1.125	9,000

The horsepower per mile of line decreases rapidly as the spacing decreases. Actually our knowledge of thermodynamics predicts this fact. The smaller the pressure rise is per station, the closer the actual (polytropic) compression line is to the adiabatic compression line.

The drivers for all compressors would be similar and designed with additional horsepower and speed. A line expansion may be simply and quickly accommodated with this forethought. An over-simplification will illustrate the general point. Change[7] the inlet guide vanes in each compressor and increase the operating speed 15 per cent. The pipe line flow is increased from 350,000,000 std. cu ft per day to 400,000,000 cu ft.

The foregoing features of centrifugal compressors may be compared with those of an axial compressor. Fig. 3 graphically presents a basic difference in the characteristics. The steep pressure-flow, constant speed line and the flat horse-power characteristic over the range of flow predicts suitable operation at high load factors alone. Further, the operating speed is a function of the inlet volume. A flow of 20,000 cfm requires a speed of 12,000 rpm. Even 600,000,000 std. cu ft per day at 800 psia is 55 per cent of this flow. The speed is proportionately higher.

The prime mover is important as the final step to general application of centrifugals and axials. An ideal machine would have many of the following qualities:

a. The operating labor requirements are low and the future possi-

[1]The exception is the Texas Eastern Transmission Corporation.

[2]"Centrifugal Compressors on the Texas Eastern Transmission Corporation Systems," by E. A. Koenig, *Oil and Gas Journal*, June 29, 1950.

[3]1947 marked advent of commercial boosters.

[4]The ratio 1.262 occurs at 850 ft per second with a pressure coefficient of 0.50 and an inlet temperature of 60 F.

[5]Based upon the Weymouth Formula neglecting compressibility.

[6]Ibid 5 neglecting valve losses.

[7]Texas Eastern Transmission Corporation station engineers accomplish this in 20 minutes per compressor.

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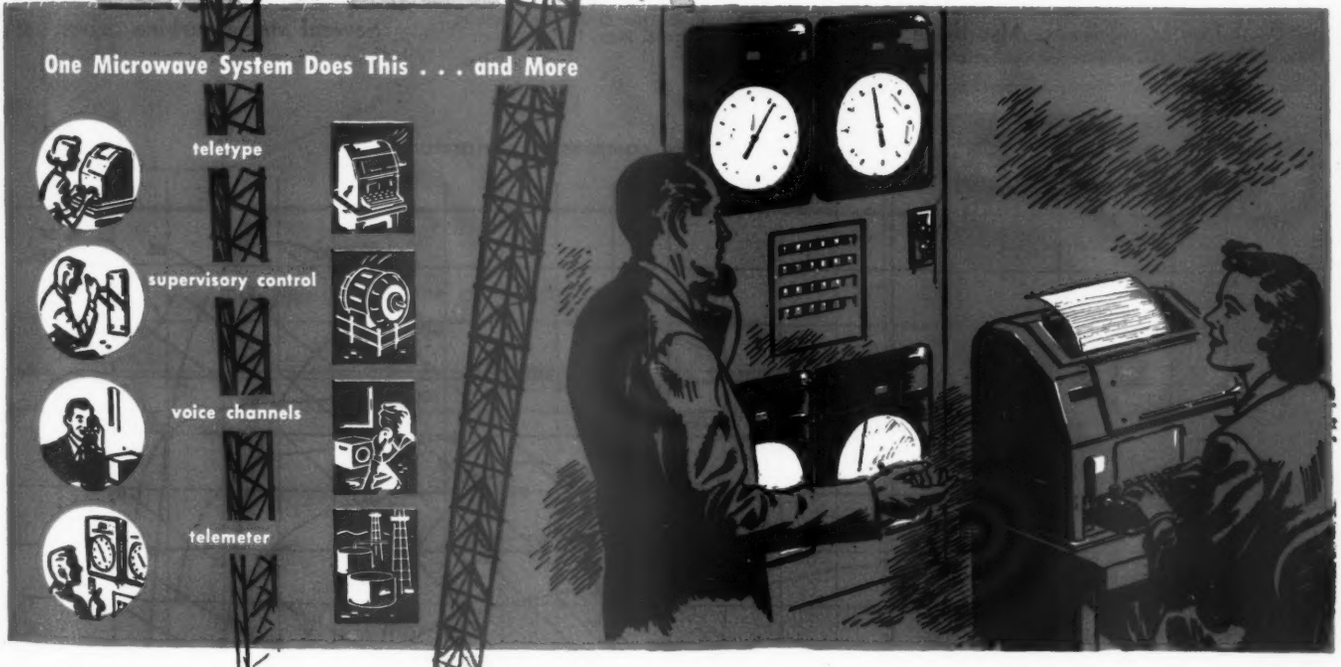

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bilities of near-automatic stations considered.

b. The speed of the driver should match the requirements of turbo-machinery.

c. The speed of the driver will be variable over a wide range above and below the compressors design point without loss in thermal efficiency.

d. The water requirements of the unit are small or unnecessary.

e. Other considerations such as the cost of installation, spare parts, maintenance, and general intangibles shall be kept in mind with respect to other type units.

Three general methods of drive, proved in design and performance, are available from many manufacturers. These are reciprocating gas engine, the electric motor, and the steam turbine. A fourth type, which has all indications of fulfilling the foregoing requirements is a gas turbine of the design being tested by Clark Bros. Co., Inc.

The gas engine may lead itself to driving turbo-machinery due to its high thermal efficiency. It does possess the fundamental disadvantage of a low speed and horsepower when related to booster requirements on trunk lines. A speed increasing gear will overcome the former obstacle with a resultant loss in efficiency. Also there is the probability of interposing a fluid coupling between the engine and the gear unit. This will obviate the transmission of power pulsations to the gearing and will further reduce the overall efficiency.

The electric motor has been the driver used on many pipe line applications due to the Texas Eastern Transmission Corporation. This company took over the former "Big Inch" and "Little Inch" oil lines from the government at the close of World War II. The agreement to surrender the lines to a private company for the transmission of natural gas was subject to certain restrictions.[8] One stipulation covered the ability of the corporation to reconvert the line to oil transmission when a national emergency required it. To facilitate such an eventuality, the boosters were designed to be driven by the existing pump motors. This project was complicated by the reverse procedure of designing compressors to be driven by existing motors.[9] The compressors were placed on the foundations formerly occupied by the pumps.

Overall, the provisions of the agreement outweighed the disadvantage of high power costs, a factor that precludes many motor applications.

Salient pole motors are not capable of a speed necessary to develop an economical pressure ratio.[10] Hence, a gear is required. A two-pole induction or synchronous motor may be directly connected but the low ratio and inflexibility of operation due to lack of speed control is difficult to justify. A variable speed coupling may be used, but it is not a commercial item in the necessary sizes and would be uneconomic. Wound rotor motors are also expensive probabilities that should be carefully evaluated and compared with turbine drives described hereafter.

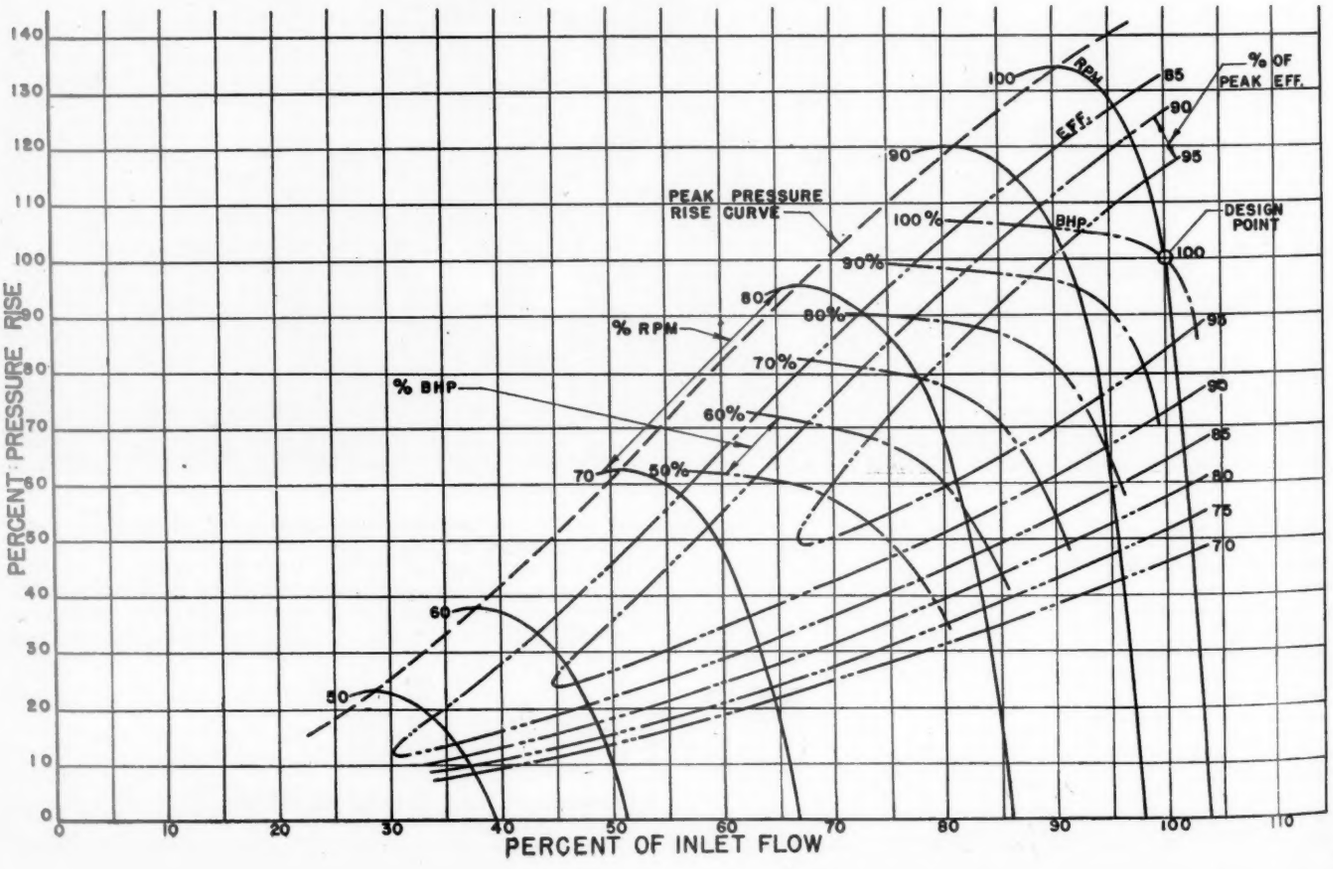
A steam turbine may be advantageously applied when water is available in sufficient quantities. The unit would operate condensing in order to obtain high efficiencies though the water demands are substantially increased. The absolute vacuums are higher than central station practice, since there is small gain in efficiency at such low vacuums with commercial mechanical drive turbines for this relatively high speed duty. Fewer turbine stages are therefore employed than is customary for 3600 rpm electric power generation practice.

Several steam turbine driven cen-

[8] "Centrifugal Compressors Come of Age," by B. D. Goodrich, AGA Spring Meeting, Houston, Texas, 1948.

[9] "Centrifugal Compressor for Pipeline Duty," by J. E. McCarthy, Pacific Coast Association, San Francisco, California, May, 1950.

FIG. 3. General axial flow compressor performance.



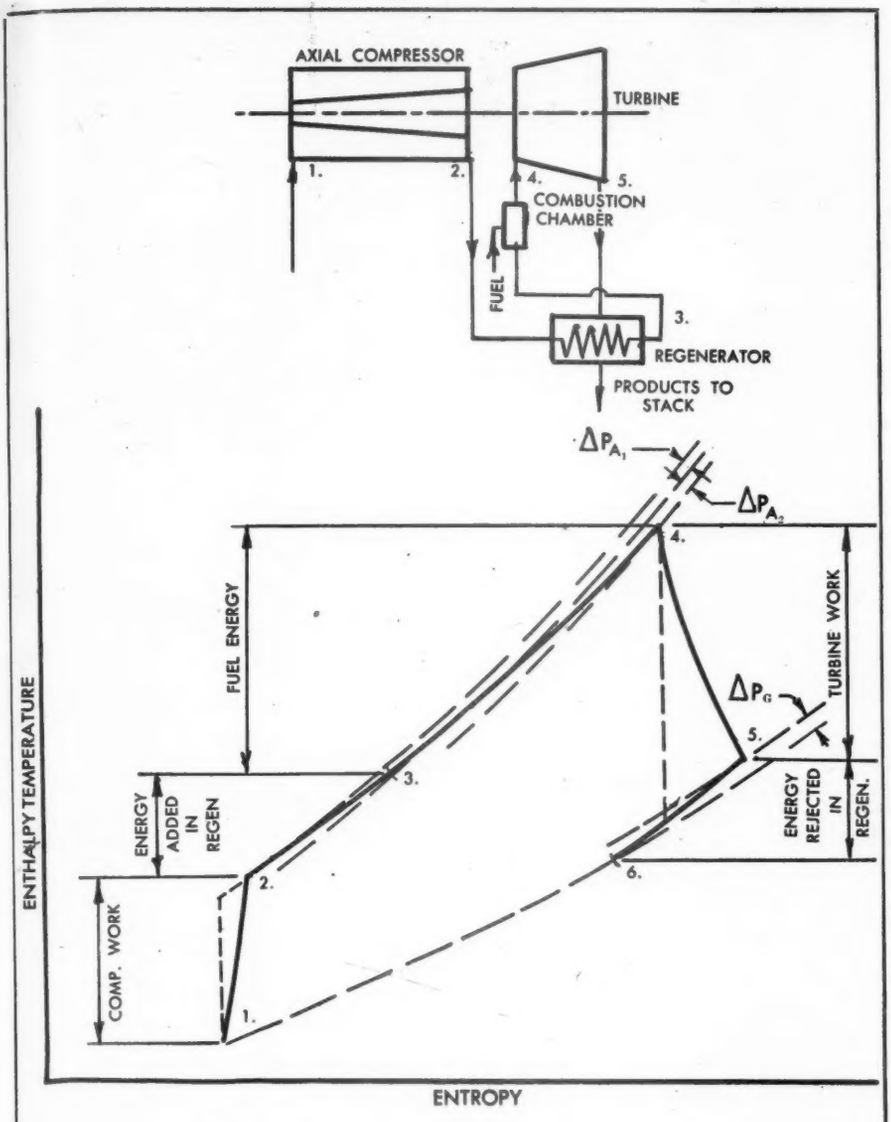


FIG. 4. Open gas turbine cycle with regeneration.

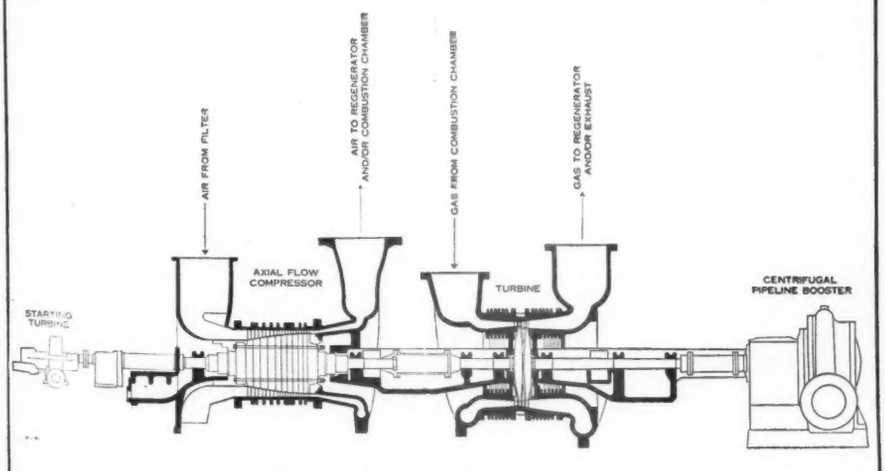
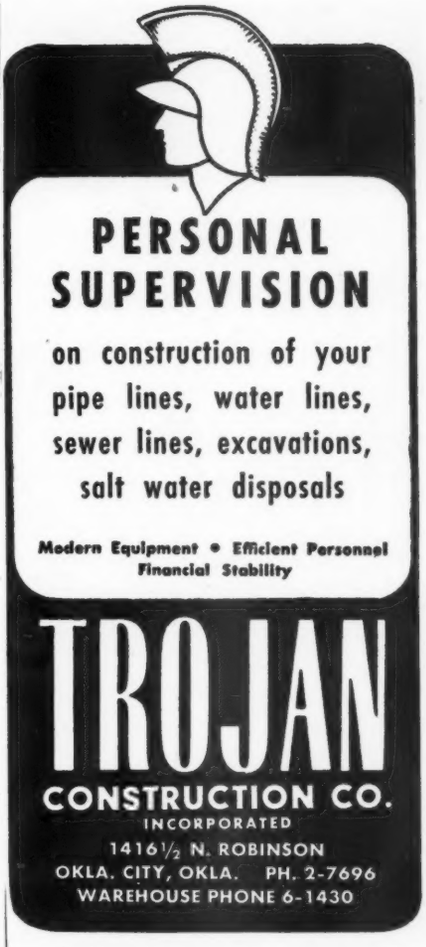


FIG. 5. Model 503 gas turbine, 5500 hp, 6500 rpm, to drive centrifugal pipe line booster.



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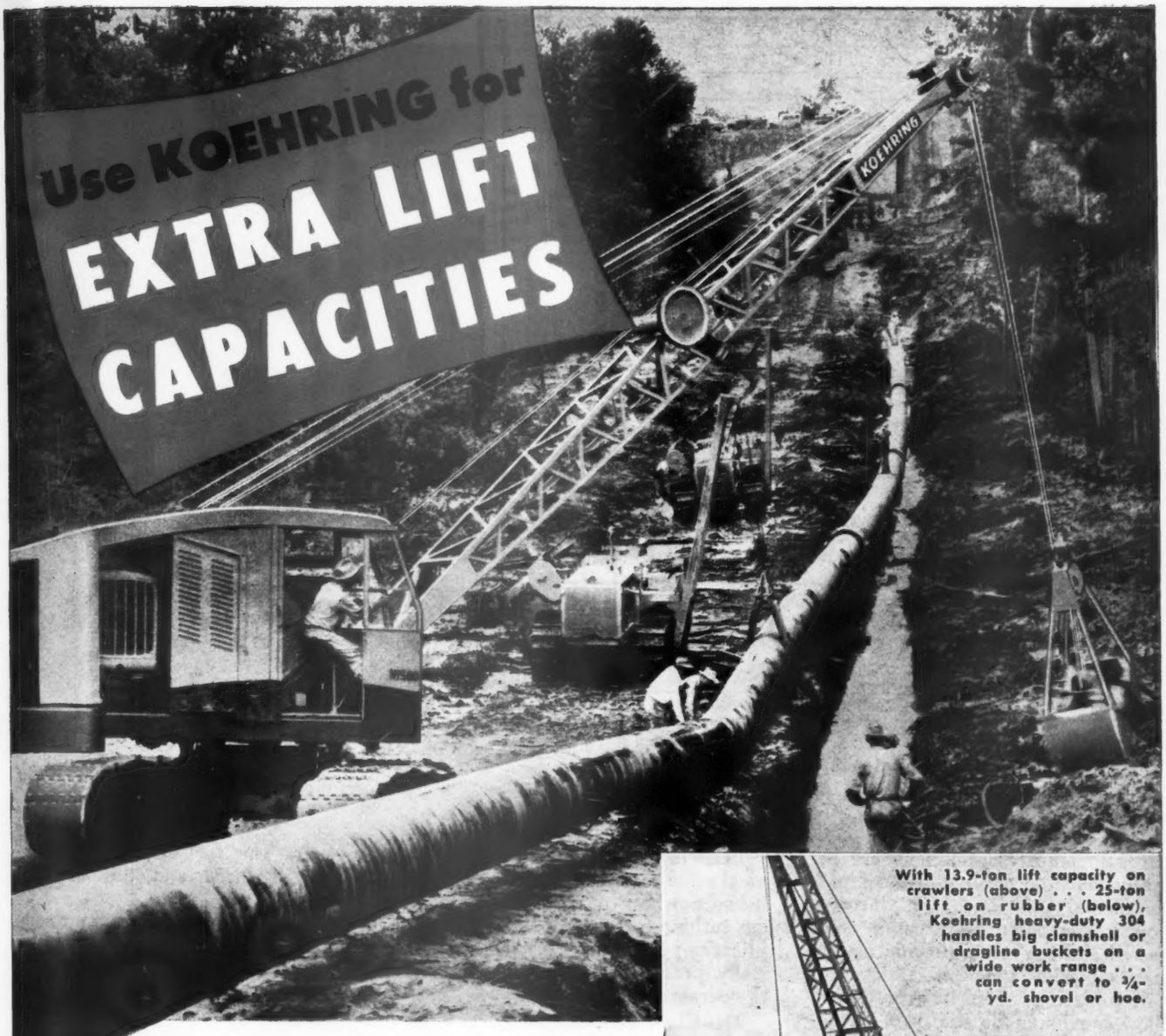

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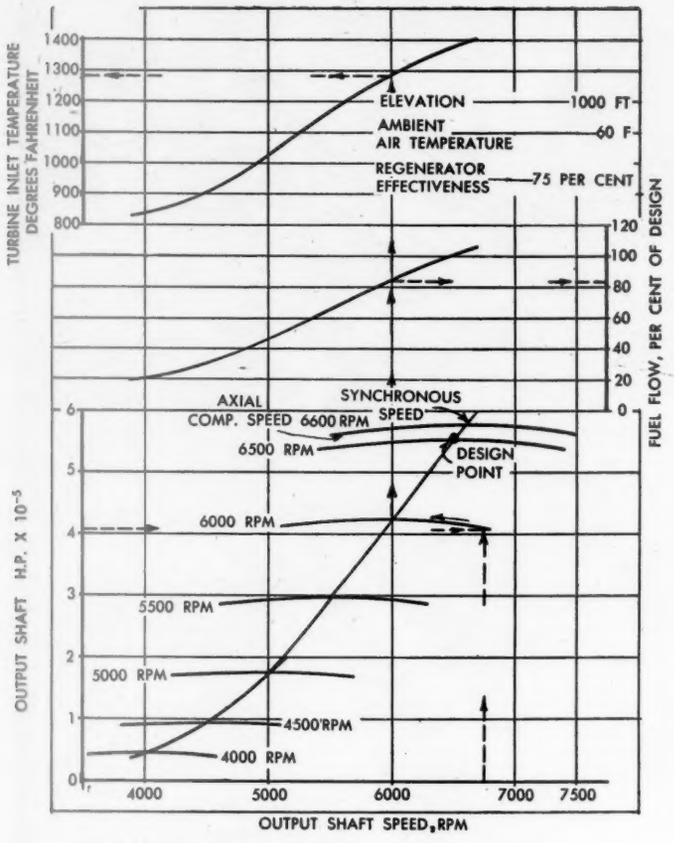


FIG. 6. Estimated performance of gas turbine unit Model 503.

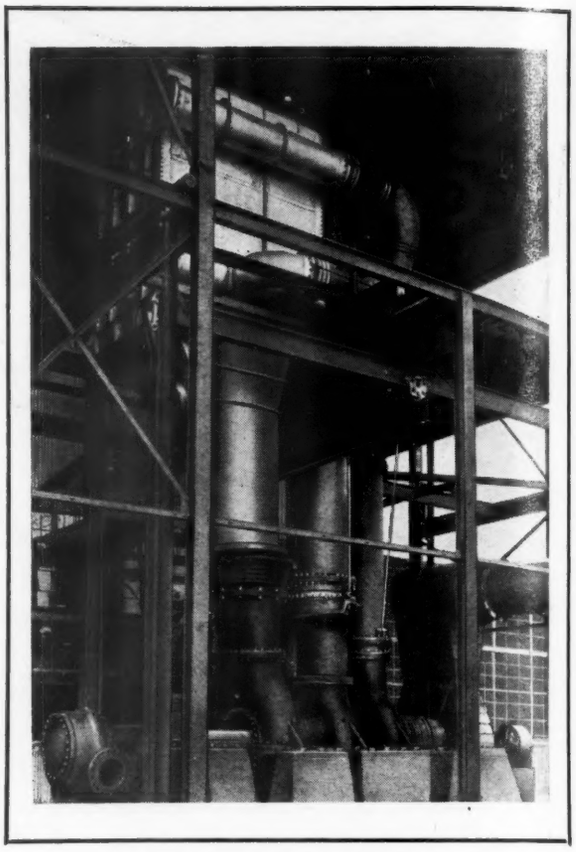


FIG. 7. Gas turbine now undergoing performance tests.

trifugal compressor stations are being installed on the line of the Transcontinental Gas Pipe Line Corporation.[11] The compressors were engineered and the steam turbine readily matched with sufficient additional horsepower and speed incorporated to allow maximum flexibility of operation. Inlet steam conditions of 600 psig and 750 F or 825 F, exhausting to 2½ in. Hg absolute are used. Our experience indicates that these conditions are favored. They appear to be economic though 825 F may be used in the future. An exception to this would, of course, occur where it is possible to work out a steam balance with an adjacent hydrocarbon recovery plant. In any case, 12,000 rpm represents the upper limit of speed for general pipe line application. This precludes direct connection by any commercial driver to axial compressors in the capacity range that is noted above.

The gas turbine shown in Fig. 7 is not subject to the limitations of high power costs and the need of water associated with the motor and steam turbine respectively. As it also possesses the advantage of these drivers, it should be the answer of our lifetime to the compressor drive problem.

[10]A four-pole synchronous motor will produce a ratio of approximately 1.09 on the present Texas Eastern Transmission line.

[11]Stations 5, 7, and 10.

Prior to the metallurgical and technical advances during the past decade, it had not been possible to develop a gas turbine for general industrial application; however, it is now commercially practical to design machinery to operate on the Brayton cycle.

The Clark unit, unique in its position at this date, represents an answer to the needs of the oil and gas industry. It evolved from a study and evaluation of the many daily compressor problems handled by the company. The rating, 5500 hp and 6500 rpm,[12] is the mode of a normal distribution of these daily compressor selections. The unit operates on a simple open cycle with regeneration. This is schematically illustrated in Fig. 4. It is considered to be the optimum combination of the five general paths that are open to this cycle for high overall efficiency.

a. The easiest way to high thermal efficiencies is an increase in the turbine inlet temperature. It is limited by the desire for long turbine life to around 1400 F with present materials.

b. The second path is high component efficiency.

c. The last method incorporated in the Clark design is regeneration. This recovers the turbines exhaust energy ahead of the blower with the incoming air. The fuel requirements are thereby reduced and the efficiency raised.

d-e. Intercooling between air compressor stages and reheating between turbine stages requires water and unjustifiable complexity in relation to the proposed duty. If water is available, it could be used. In general, the first three methods alone will be used by the Clark unit.

Speed flexibility is obtained by using two shafts in line, with the single wheel on each coupled by a hot gas stream only. (Fig. 5.) One shaft is rigidly coupled to the air compressor. This forms a gas generator unit that has a surplus of power represented in the gas flowing to the second wheel. The latter shaft transmits useful energy to the pipe line booster. It may operate above or below the generator shaft speed with small variation in thermal efficiency as shown in Fig. 6. This is possible because the inlet temperature remains high. A single shaft turbine may procure speed control only by reducing the temperature, and, of course, the thermal efficiency.

The Clark gas turbine (Fig. 7) is undergoing comprehensive performance tests at this time. Since it is the only unit of this type extant today, the results of this operation will be noteworthy in the progress of American industry. * * *

[12]Measured at 1000 ft with an ambient air temperature of 60 F.

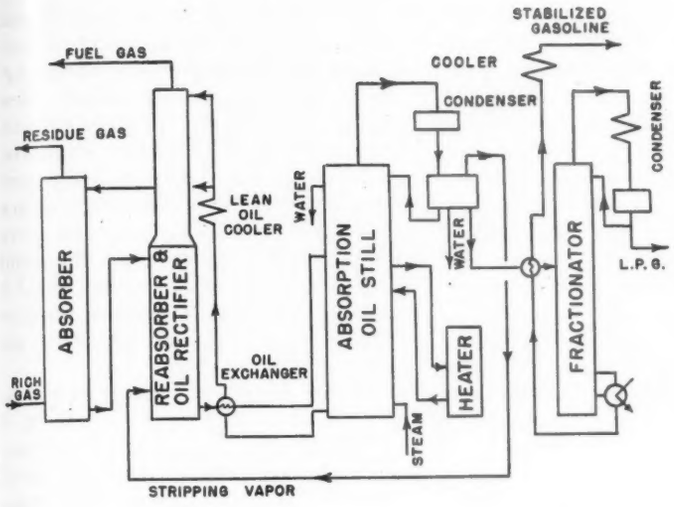


FIG. 1. Flow diagram of an absorption type plant.

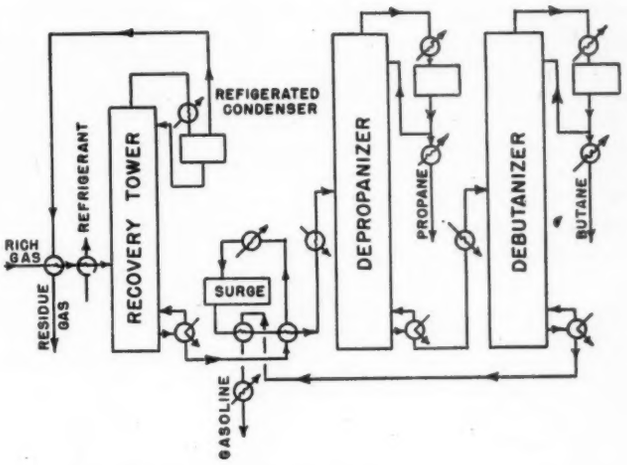


FIG. 2. Vapor rectification system.

Removal of Liquids From Natural Gas Before Entering Pipe Lines*

Liquids decrease capacity, increase corrosion, and under certain conditions can stop the flow of gas completely

J. H. ECHTERHOFF

EVERYONE engaged in the gathering and transmission of natural gas has experienced trouble from the presence of liquids in pipe lines. Liquids decrease the capacity of a pipe line, increase corrosion problems, and under certain conditions can stop the flow of gas completely by the formation of hydrates. For these reasons the prevention of the formation of both hydrocarbon and water liquids in the gas system is necessary to maintain maximum pipe line efficiency.

The separation of liquids from a natural gas stream is a mechanical problem as old as the natural gas business. There are numerous separators on the market, each of which will satisfactorily accomplish the desired separation of any liquids that have been formed at the point of separation. It is to be noted, however, that mechanical separators are seldom 100 per cent efficient and that if manufacturers' rated capacities are not adhered to, serious carry-over of liquid can be expected.

The real problem, however, is not the separation of gas from a liquid—it is rather the "conditioning" of the gas so that from the time it enters the pipe line, initially, until it reaches the ultimate consumer, no liquids will be formed.

The removal of "liquefiables," or constituents that are in a vapor state, but which can be expected to condense with a change in temperature and/or pressure, is somewhat more difficult and it is the purpose of this paper to discuss the more popular methods used and some of their advantages and disadvantages.

There are two types of liquefiables that must be controlled if we are to prevent the formation of liquids in the pipe line. These are (1) hydrocarbons and (2) water.

Control of Hydrocarbons

The control of hydrocarbon liquefiables is accomplished by one of two methods:

1. Processing through a natural gasoline plant.
2. Separation through a low temperature separator.

Any plant processing natural gas for the production of liquid products, without chemical change, is normally referred to as a natural gasoline plant. Besides the natural gasoline, however, such products as ethane, propane, butane, isobutane, isopentane, motor fuel, kerosine, and residual fuel oils are made from the heavier hydrocarbons that have been extracted from the raw gas stream. The result

The Author

J. H. Echterhoff is assistant to the operating superintendent of gasoline plants, United Gas Pipe Line Company. He is a graduate of Texas A. and M. College with a degree in chemical engineering. He has been with United Gas Pipe Line since his graduation in 1936, with the exception of four years when he served in the U. S. Army Corps of Engineers.

*Presented before the Transmission Session of the Southern Gas Association, Biloxi, Mississippi, April 23-25, 1951.

is that where natural gas is processed in a gasoline plant, it must be considered as one of a number of valuable plant products.

As might be expected, there is a wide variation in the individual plant processes. Depending upon the primary means of initial separation from the raw gas stream, we can classify these as (1) absorption plants and (2) refrigeration plants.

In absorption plants, the heavier hydrocarbons are removed from the incoming raw gas by contacting with a light absorption oil very similar to kerosine. A flow diagram of such a plant is illustrated in Fig. 1. The ramifications of this plant are many, with the primary purpose of each being to either absorb more and/or to retain more of the absorbed products. The absorption plant is adaptable to most any raw gas condition, but to the gas pipe line can have one distinct disadvantage — in the absorber the temperature of the gas and oil is raised by the heat of absorption. The oil is carrying an appreciable quantity of water, either in solution or suspension, which it gets from the stripping steam in the still. The residue gas from the absorber becomes saturated with water at this elevated temperature. If this residue gas is not dehydrated, it can be the source of a large quantity of liquid water in the gas pipe line. If the residue gas is dehydrated without some form of cooling to compensate for this temperature rise, it will greatly aggravate the dehydration problem. It is possible to use dry gas for stripping in the still or to remove the water from the lean oil before returning to the absorber in order to prevent the residue gas from increasing in water content over that of the inlet gas to the absorber.

Figs. 2 and 3 illustrate two different types of refrigeration systems. These systems are not as adaptable as the absorption system to all gases, being limited to gases that are classed as "rich" in liquefiable hydrocarbons.

The low temperature separator method of water and liquefiable hydrocarbon removal on high pressure gas distillate wells is a method that has gained relatively recent popularity. This method will be covered in detail by another paper in this meeting so will not be elaborated on here; however, we should not overlook the fact that this method has the limiting feature of high pressure drop.

The calculation of temperature and pressure conditions at which a particular gas will begin to condense hydrocarbons, commonly called "dew point," is a fairly complex calculation, well covered in the literature, and beyond the scope of this paper; however, it is fairly common practice to regard gas that contains not more than 0.2 gal of gasoline per thousand cubic feet, by the standard NGAA charcoal test, to be acceptable for pipe line pressures up to 900-1000 psi without condensation.

Although drip gasoline is an expensive nuisance to the gas pipeliner, it is liquid water that is his chief concern. Liquid water in the presence of natural gas hydrocarbons and under certain temperature and pressure conditions may form a hydrate that is a solid ice-like material. Under extreme

FIG. 3. Refrigeration-compression system.

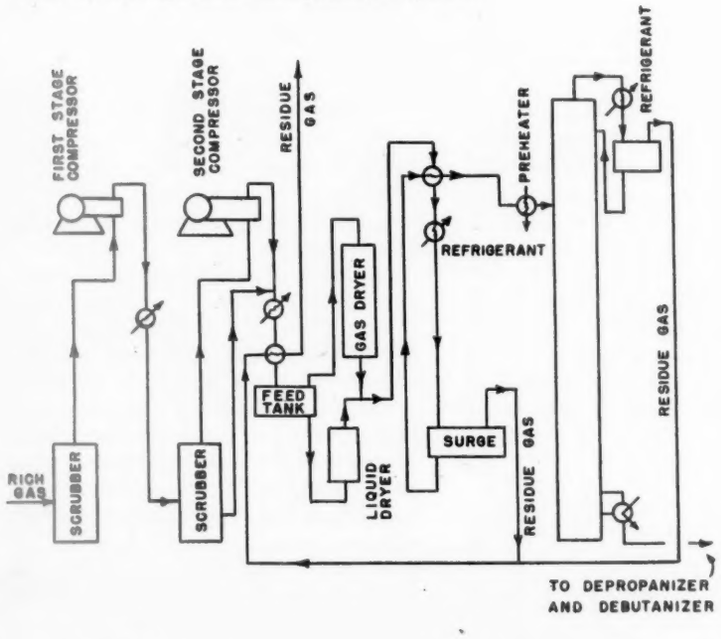
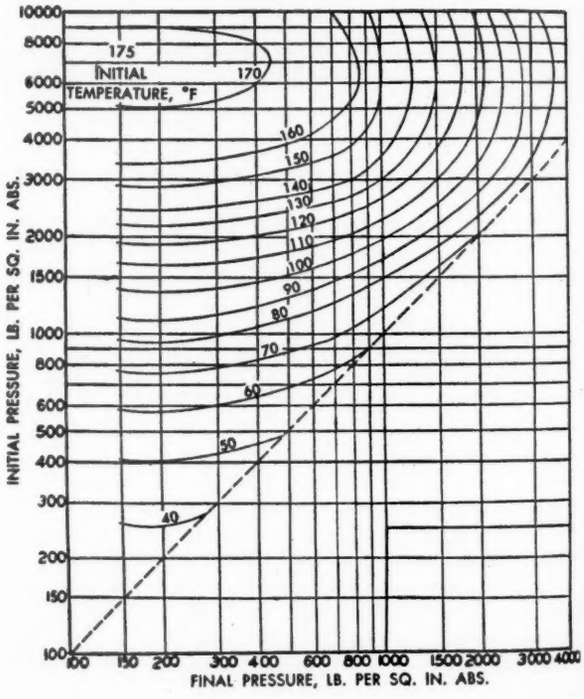


FIG. 5. Permissible expansion of a 0.6 gravity natural gas without hydrate formation.



Uses of the Chart

Fig. 5 may be used to solve two types of problems with examples as follows:

1. How far may a 0.6 gravity gas at 2000 lb pressure and 100 F be expanded without danger of hydrate formation? The answer, from Fig. 5, is 1050 lb per sq in. abs.

2. How far may a 0.6 gravity gas at 2000 lb and 140 F be expanded without hydrate formation? The answer, from Fig. 5, is that hydrates wil not form upon expansion to atmospheric pressure.

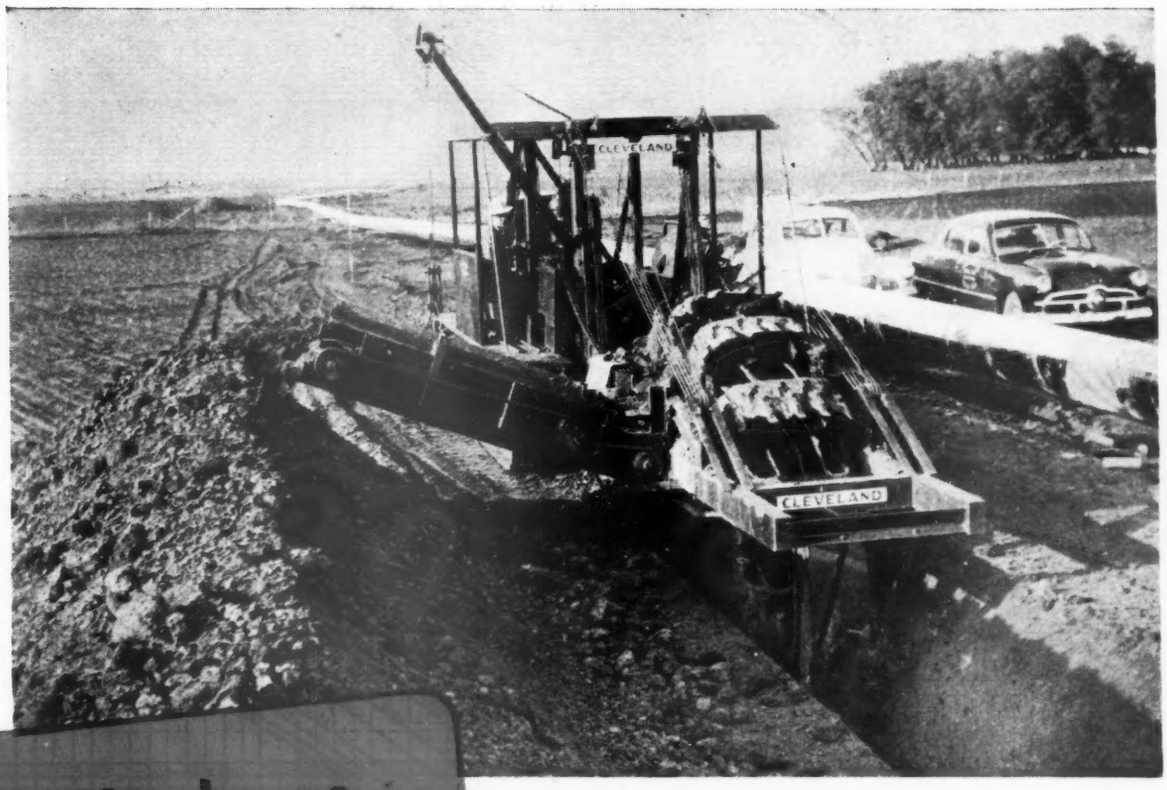
3. A 0.6 gravity gas is to be expanded from 1500 lb to 500 lb. What is the minimum initial temperature that will permit the expansion without danger of hydrates? The answer, from Fig. 5, is an initial temperature of 90 F or above.

4. A 0.6 gravity gas at 10,000 lb and 140 F is expanded freely and adiabatically:

a. At what lower pressure will the temperature become 140 F?

b. At what pressure would hydrates be likely to appear if sufficient water is present?

The answer, from Fig. 5, is (a) 4300 lb and (b) 1150 lb.



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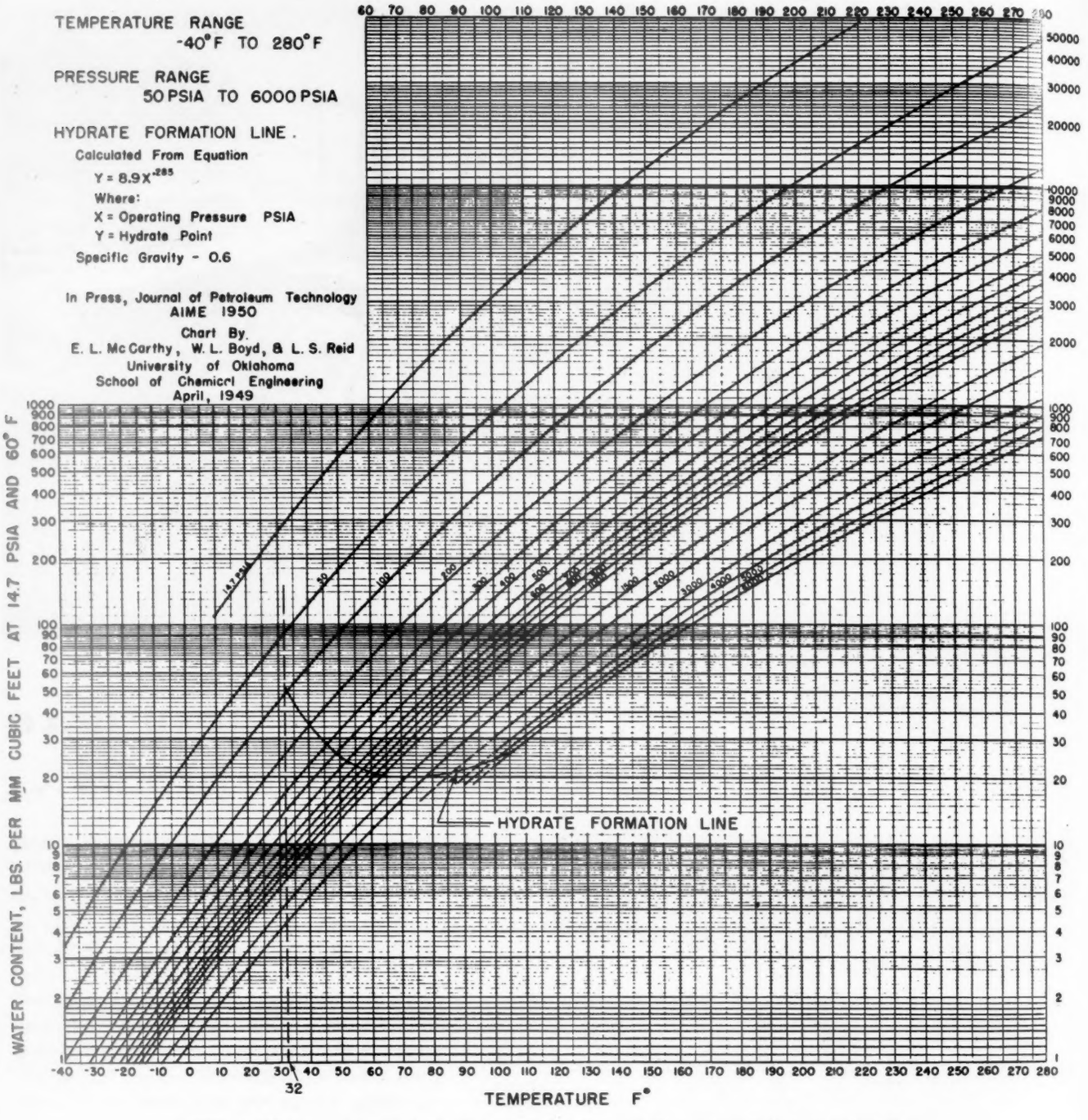


FIG. 4. Water vapor content of essentially nitrogen-free natural gas at saturation.

conditions these hydrates can pack severely enough to block a pipe line.

Fig. 4[2] presents data to illustrate the water vapor capacity of a natural gas. At a given temperature and pressure, the quantity of water shown is that when the system is at 100 per cent relative humidity. As illustrated, the water capacity decreases with increased pressure, temperature remaining constant. The water capacity increases with temperature, pressure remaining constant. The composition of a gas affects its water capacity, but this effect is small and normally neglected.

This curve is useful for three purposes:

1. To determine the extent of dehydration necessary for a particular gas, i.e., if gas is going into a pipe line operating at 800 psi where ground temperatures are such that the gas can be expected to reach a temperature of 30 F, to what extent must the gas be dehydrated to prevent formation of liquid water?

From the curve, the 800-psi pressure line and the 30 F temperature line cross, showing that a saturated gas under these conditions holds 7.5 lb of water per million cubic feet. To prevent the condensation of liquid water, this gas should be dehydrated to a water content of not more than 7.5 lb per million cubic feet.

2. To determine the amount of water to be removed in dehydration, i.e., if the above gas was entering a dehydration plant at 850 psi at 95 F, how much water must be removed? The curve shows a saturated gas

at 850 psi and 95 F to hold 62 lb water per million cubic feet
at 800 psi and 30 F to hold 7.5 lb water per million cubic feet
Water to be removed 54.5 lb per million cubic feet.

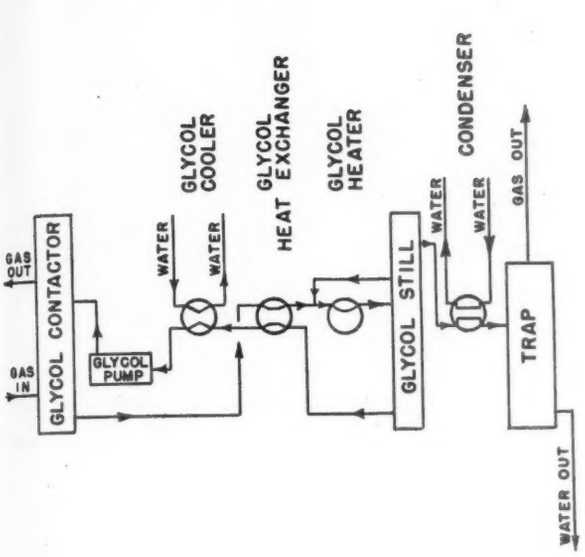


FIG. 6. Glycol type gas dehydration unit.

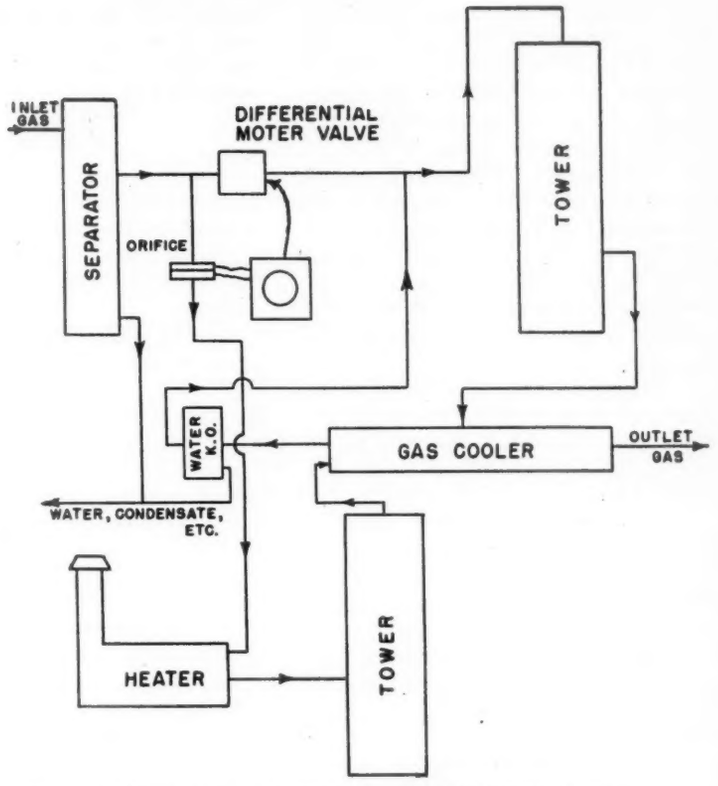


FIG. 7. Flow diagram of solid desiccant plant.

3. To predict the formation of hydrates.

A gas under temperature and pressure conditions above the hydrate line will not form hydrates.

A gas under temperature and pressure conditions below the hydrate line, and in the *presence of liquid water*, *may* form hydrates.

Fig. 5 presents data published by D. L. Katz[1] showing the permissible expansion of a natural gas without hydrate formation. This information is useful in determining the layout of a wellhead installation on high pressure gas wells to prevent hydrate formation when the gas is throttled to gathering system pressures. In gas gathering systems, particularly, it is often necessary to provide heat to the gas to keep it above the hydrate point in order to reach a central dehydration plant.

There are three water vapor removal systems now in general use:

1. Liquid desiccant system.
2. Solid desiccant system.
3. Low temperature separator.

As noted previously, the low temperature separator is being carried in a separate paper at this meeting and will not be covered in this paper.

The liquid system has the advantage of operating on a continuous cycle. The gas is contacted in an absorber and the diluted desiccant is regenerated in a small concentrator. Fig. 6 is a flow diagram of a typical liquid system. The solid desiccant systems operate on a cycle type process where two or more contactors alternately dehydrate the gas and are then regenerated by using hot gas or superheated steam. Fig. 7 is a typical flow diagram on a solid type unit.

In small installations, the liquid system will operate with little labor expense without the necessity of putting in a complicated system of controls. In the larger systems, the cycle controllers used to make the solid desiccant units automatic are a smaller relative part of the investment so that there is small difference on an economic basis.

The liquid desiccants in popular use are usually one of the glycols. The chief difficulty with the glycols is getting sufficient reconcentration without decomposition in order to get large dew point depressions. In some cases, reconcentration under vacuum gives good results.

Normally, the higher pressure gas transmission lines require dew points (point at which water will begin to condense) in the neighborhood of 30 F or less. With glycol this corresponds to a maximum allowable inlet gas temperature to the dehydrator of about 80 F. Recent developments may allow slightly higher temperature.

The solid bauxite type desiccants will give dew points in the 0 F and under range and are satisfactory to about 95 F. At this temperature they fall off rapidly in capacity. They are also subject to "dusting" with changes of velocity in the bed which, in the presence of the heavier hydrocarbons, will tend to cake, resulting in loss of capacity and increased pressure drops.

Recently, a beaded silica-gel type desiccant has been used. It will dehydrate at elevated temperatures, has good capacity, but is very sensitive to liquid water, which causes disintegration of the beads. It has an affinity for hydrocarbons, which results in a liquid hydrocarbon recovery on the regeneration cycle. This liquid can be recovered and sold to help offset the cost of dehydration. The bauxites also have this affinity for the hydrocarbons, but to a lesser extent.

Fig. 8 presents data to illustrate the effect of increased pressure drop on horsepower requirements for compression of natural gas.

Pressure drop through a dehydration plant, like pressure drops through other equipment, causes increased horsepower requirements with an accompanying increased operating cost. The liquid systems have relatively small pressure drops determined primarily by the liquid head over the trays in the contactors. The solid types have pressure drops determined by the piping, valving, and the depth and type of bed. A major portion of the pressure drop through the solid type units is a result of normally taking the regeneration gas (see Fig. 7) off the main stream before a differential valve, through the heater, the regen-

erating bed, the cooler, and back into the main stream before it enters the drying bed. If the unit is operating at sufficient pressure and the regenerating gas cooler can be assured of cooling this gas to the order of 90 F, it can then be put back into the main stream on the outlet of the plant and still assure a 30 F dew point. This will decrease the pressure drop by an appreciable amount.

In the solid type units there are a number of different tower designs being used:

1. The conventional vertical tower with either a single, or multiple, bed(s) in which the gas enters one end of the tower and leaves at the other end.
2. So called radial flow tower in which the gas enters the side of the tower, flows around an inner shell, passes through the bed into a center core and out the bottom of the core.
3. A horizontal tower divided into several compartments with an individual inlet and outlet for each compartment.
4. It is reported there is now a spherical tower under development.

The objective of each type of tower is to give uniform flow through the bed on the drying and regenerating cycle in order to use the maximum capacity of the desiccant, to provide easy access for filling and emptying the unit of desiccant and to give a minimum of pressure drop.

Summary

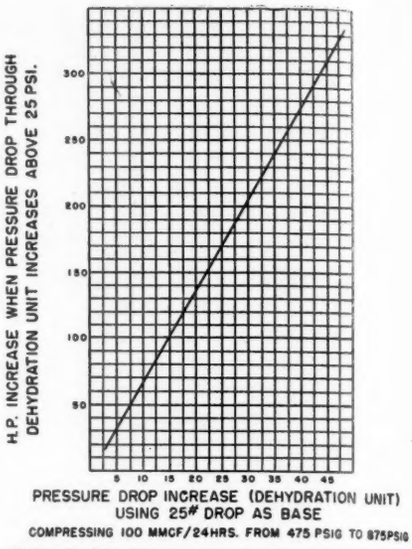
The liquefiable hydrocarbons are removed from natural gas for one or a combination of these reasons:

1. Because it is economically feasible to recover the liquefiable hydrocarbons.
2. To meet contractual specifications on the residue gas.
3. To prevent the formation of liquids in the gas pipe line.

The removal of water vapor from natural gas is done for one or a combination of two reasons:

1. To prevent the formation of liquid water at any point in the pipe line, which has the accompanying danger of the formation of hydrates.
2. To meet contractual obligations.

The removal of both liquefiables is often handled as a combination project, either on a single well or a group of wells. For water vapor removal, the type of equipment used should be determined by a careful study of the pressures existing, not only at the beginning but over the expected life of the project; pressure drops that can be tolerated and temperatures of the wet gas. In the case of the hydrocarbons, a careful economic study should be made over the life of the project with original equipment cost, operating cost and ultimate liquid hydrocarbon recovery and value given proper consideration.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250
200
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50
5 10 15 20 25 30 35 40 45
PRESSURE DROP INCREASE (DEHYDRATION UNIT) USING 25# DROP AS BASE
COMPRESSING 100 MMCF/24HRS. FROM 475 PSIG TO 875PSIG

FIG. 8. Hp increase vs pressure drop increase (dehydration unit).

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2. McCarty, Boyd and Reid, *AIME Journal of Pet. Tech.*, Vol. 2, 241-242 (1950). * * *

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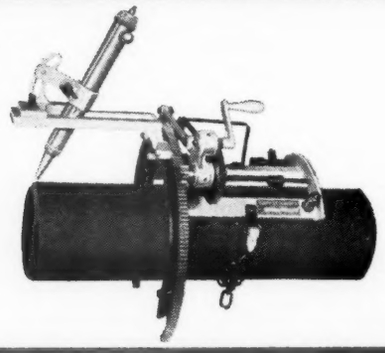

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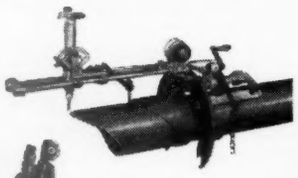

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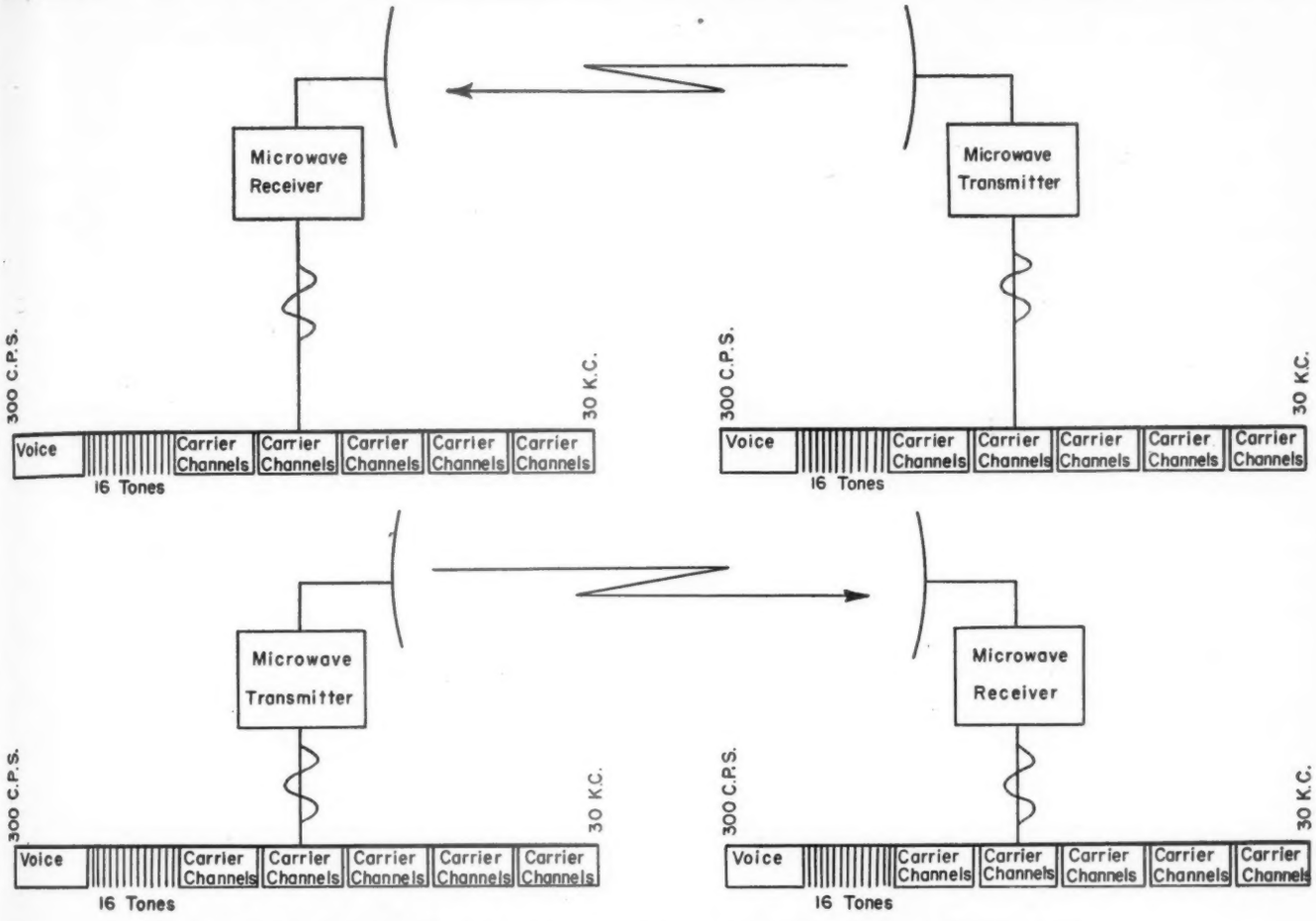


VOICE, TELEMETERING CONTROL, SUPERVISORY, AND VOICE CARRIER APPLIED TO A MICROWAVE SYSTEM ON A FREQUENCY DIVISION BASIS

USEFUL DISPATCHING TOOLS†

Telemetering, remote control, and supervisory facilities as applied to communication networks

EDWIN D. NUTTALL*

Telemetering, remote control, and supervisory systems, individually or collectively, provide the gas dispatcher with three very useful tools that, when properly applied, facilitate system operation:

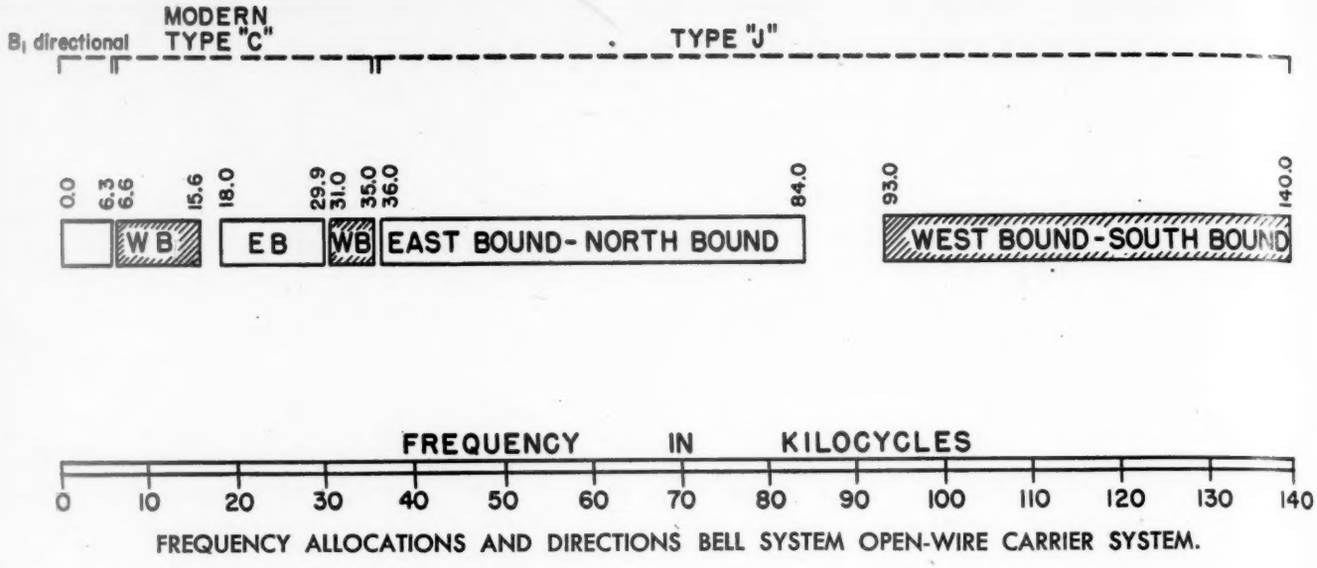
(1) Telemetering or remote metering of a variable such as pressure, flow, or temperature; (2) the control of remote valves and pressure regulators, and (3) the transmission in the return direction of supervisory signals that say in effect "order received and properly executed" can be achieved through the proper selection and application of audio and carrier telegraph signal transmitters and receivers.

Telemetering and supervisory circuit signal transmitters for the simpler circuits can be of the On-Off variety as they do not necessarily have to include Fail Safe protection. Signal receivers associated with these transmitters are only required to close a relay through the use of proper circuitry, which in turn controls the associated device.

Signal transmitters and receivers used for remote control and for supervisory circuits that include semi-automatic control operation must provide some sort of Fail Safe protection. This is required to insure no change in the controlled device in case of power or signal failure. Time delay relays provide protection against operation caused by lightning or other surges. By the use of audio or carrier telegraph transmitters and receivers of

*Electronics engineer, Research Department, United Gas Corporation.

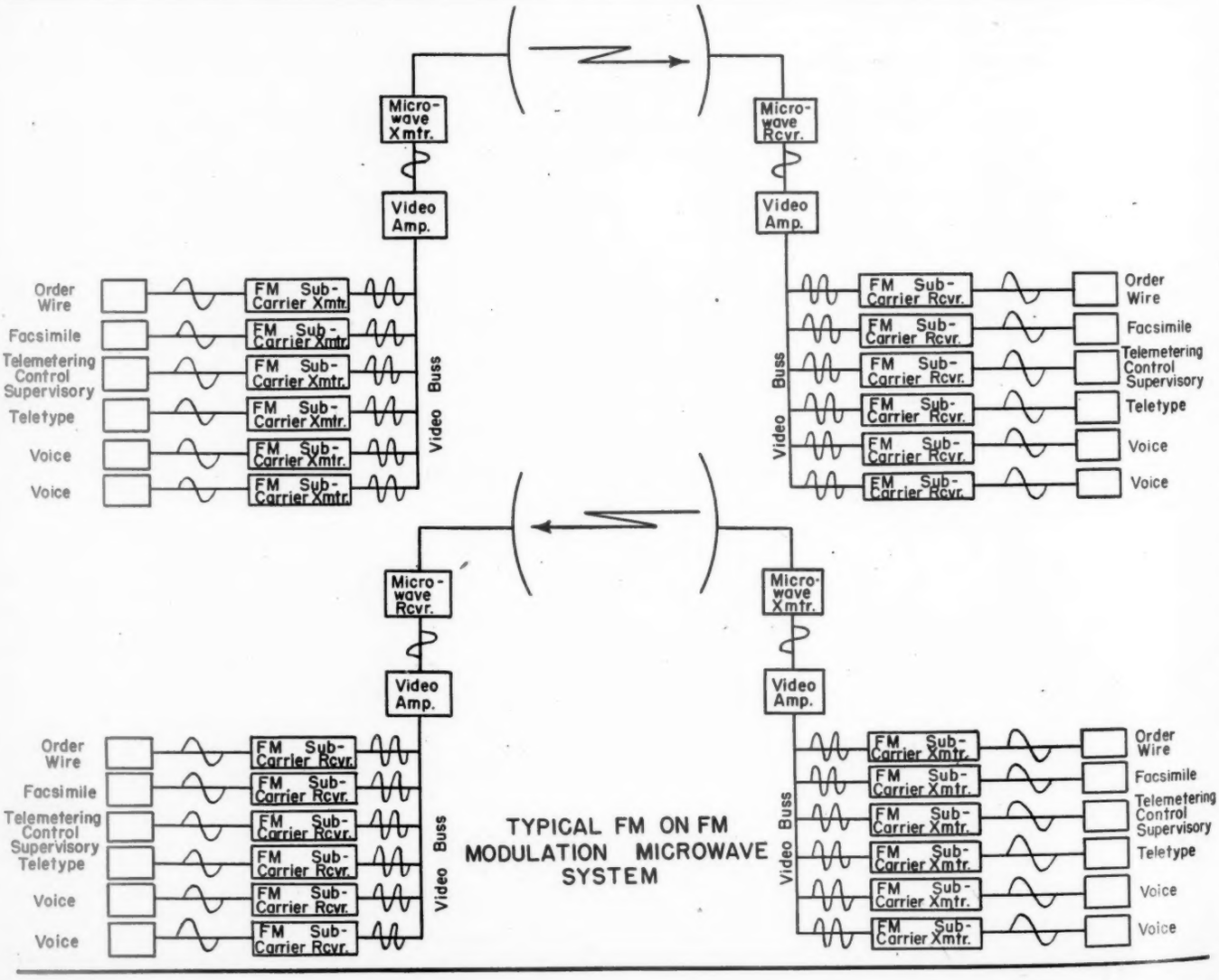
†Presented before the Southern Gas Association, Biloxi, Mississippi, April 23-25, under the full title, "*The Application of Telemetering, Remote Control, and Supervisory Facilities to Communication Networks.*"



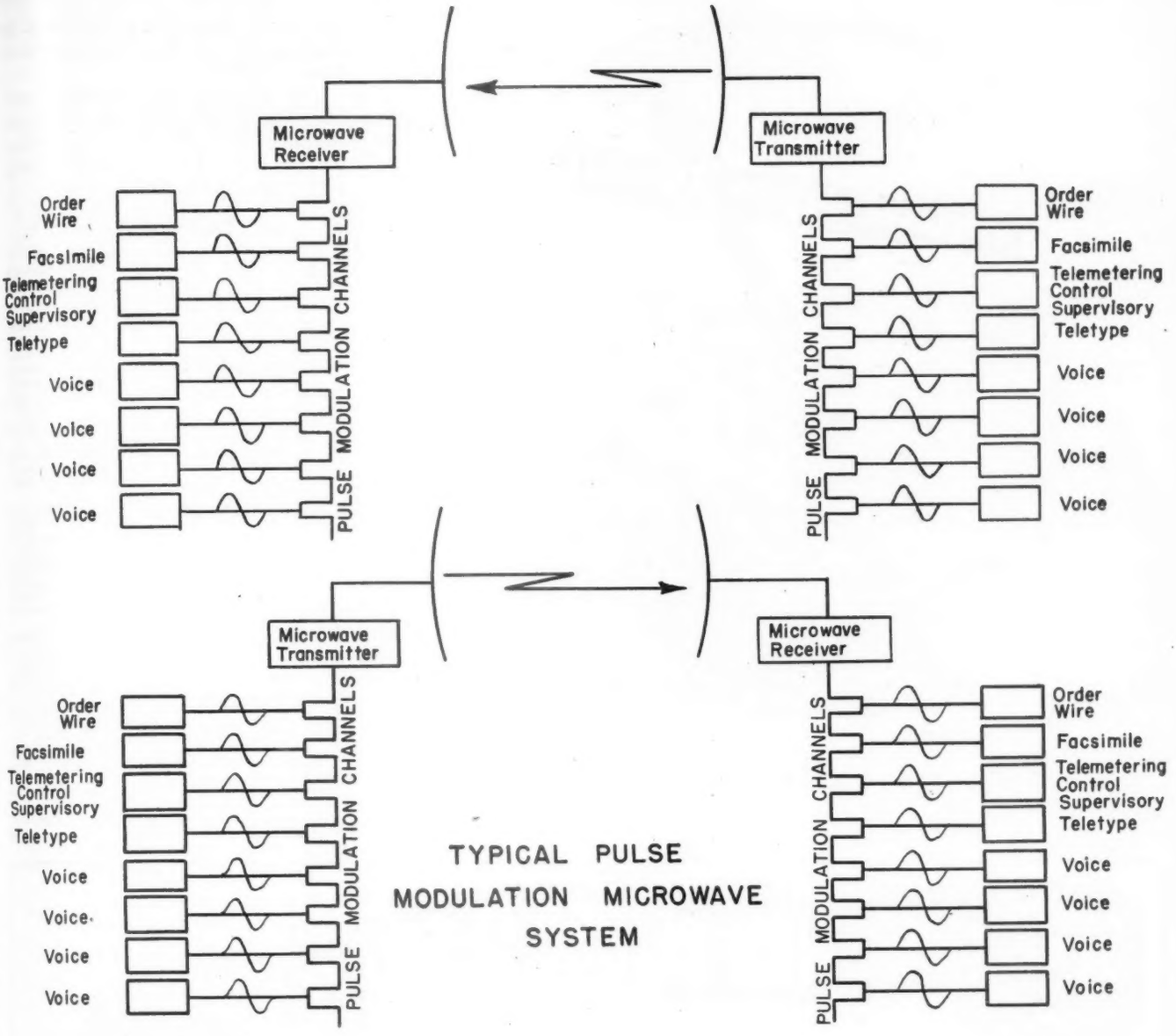
FREQUENCY ALLOCATIONS AND DIRECTIONS BELL SYSTEM OPEN-WIRE CARRIER SYSTEM.

the frequency shift variety, signal circuit and power circuit Fail Safe protection can easily be achieved, thus virtually eliminating false control or false supervisory operation caused by voltage transients that may be induced into the signal circuits. Complex control and Fail Safe protection problems can readily be solved by the proper application of two or more signal shift transmitters and receivers in cascade combinations. Frequency shift equipment is quite suitable for telemetering circuits. Any of the telegraph signal transmitters and receivers mentioned can be used successfully over wire lines or microwave systems.

Microwave systems up to and including those in the 960-mc band assignment usually are phase modulated



TYPICAL FM ON FM MODULATION MICROWAVE SYSTEM



TYPICAL PULSE MODULATION MICROWAVE SYSTEM

for an effective bandwidth of approximately 30 kc. Multiplexing of voice and telegraph signals into the microwave system is on a frequency division basis. In effect, the only difference between such microwave systems and a wire line is that the microwave system can be considered to be a 4-wire line, which can carry a total of 7 voice channels (or equivalent circuits) in each direction, as compared to the wire line, which is usually considered a 2-wire system and can carry a total of 4 voice channels (or equivalent circuits) bi-directionally. Approximately 16 telegraph type signal transmitters or receivers can be multiplexed into the spectrum space required for 1-voice channel in one direction.

In the application of telegraph signal transmitters or receivers to wire lines or microwave systems it is recommended that they be multiplexed directly into the system without the use of additional channeling equipment when possible. This will give some additional circuit protection.

Over properly transposed wire lines designed to operate directional-wise according to The Association of American Railways directional agreement, voice and carrier telegraph frequencies are available for use up to 150 kc. This is the width of the entire "C" and "J" carrier frequency spectrum. When such a communication system is to operate in its entirety over a telephone line remote from other telephone and telegraph lines, special transposition schemes and AAR directional operation are not required.

Frequency division multiplexed modulation is used on most microwave systems operating on 960 mc or below. Above 960 mc both frequency division and pulse methods of modulation are in common use. The more common types of frequency division multiplexing use voice and telegraph carriers designed for wire service in the "C" and "J" carrier ranges. There are, however, some types of frequency division multiplexing that require special FM subcarriers, which in turn contain the desired signals. Each FM sub-carrier is the equivalent of a voice channel. There are in common use several different types of pulse modulation, each one of which requires multiplexing circuitry suitable only to that particular type of pulse operation. In these systems each pulse is the equivalent of a voice channel.

In either the frequency division multiplex systems using standard telephone types of sub-carrier equipment, those using FM subcarriers, or those using pulse techniques when telemetering, control, or supervisory signals are used for subcarrier modulation. The loss of a sub-carrier channel means the loss of all signals carried by this sub-channel. This point should always be considered in system design.

In all of the wire line or phase, pulse, and frequency modulated microwave systems mentioned, suitable audio or carrier telegraph type signal transmitters and receivers can be used for accurate metering, con-

trol, and supervisory functions including adequate Fail Safe provisions when required.

The following sketches show methods of applying telegraph type signal equipment to wire line and microwave systems. A bibliography of helpful literature is included.

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Operating Aspects of Gas Storage Accounting†

A discussion of the economic phases of underground storage, which has become a major factor in the natural gas business

A. A. CULLMAN*

A REVIEW of the American Gas Association monthly magazine for April brings forcibly to attention that the gas industry has gone into the banking business in a big way. According to an article in that issue, the industry is operating more than 100 savings banks.

A savings bank is an institution where you can keep your money with safety and get it out when you want it. At December 31, 1950, the gas industry had almost 350 billion cubic feet of gas in underground savings banks. These might be referred to as demand deposits because the gas is safely there until we need it—and it can be withdrawn on demand.

Only fragmentary figures are currently available but these would seem to indicate that within a very few years somewhere around 1 trillion cubic feet will be in storage with a maximum daily delivery approximating 3 billion cubic feet.

In the past, there has been a number of speakers on this rostrum to discuss underground gas storage. Therefore, it is not necessary to go into the detailed history and background of storage operations from its operating aspects.

I do ask your indulgence for just a moment to consider the background of the economic side. Prior to 1936 underground storage was conducted only on a small scale. In 1936, some Ohio fields were activated. In 1937, some Pennsylvania operations began. These 1936 and 1937 operations, limited primarily to the relocation of Appalachian gas, although they seemed substantial at the time, were not of such magnitude that any considerable financial problems accompanied them.

The demand of distant markets requiring such large quantities of gas from the Southwest fields has so multiplied the economic advantages of storage operations, through improved load factors, that underground storage has become a major consideration in the natural gas business.

The steady increase in financial importance of gas storage operations is related not only to the obvious economic advantages but also to the dollars invested in storage inventory.

In our own system, if present plans materialize, investment in gas storage inventory within two years will become the second largest item on our balance sheet, exceeded only by the value of physical property. Large storage inventory investments appear in the balance sheets of other systems.

Naturally an item of such magnitude on the balance sheet of any company gets a lot of attention from its management, its independent auditors, and the investors in its securities. Numerous questions must be answered.

Summed up, the combined approach of these various interests might be stated somewhat as follows:

> "Yes, we know there is gas in the fields. There has to be. It comes out in the winter, doesn't it? But do the fields still hold all the gas your balance sheet shows as inventory? How do we know it is there? Will it be recovered?"

This combined approach may be resolved generally into five basic problems. There are:

1. The safety of the gas in the storage field.
2. The periodic determination of the quantity of gas in the storage fields.
3. The recording of all gas removed from the storage fields by withdrawal for market or in any other way.
4. The segregation of the storage inventory between fixed capital and current assets.
5. The segregation of storage expenses from other operating expenses of the enterprise.

The first question is "How safe is the inventory?"

There is no longer any doubt within the industry that the gas in underground storage pools is perfectly safe except under unusual circumstances surrounding specific pools, such as water encroachment. If any doubts did exist at an earlier date in a few quarters, the expansion of such operations in the last decade is ample evidence that such doubts have been resolved. The following is quoted from a recent report by E. E. Roth, chief geologist of Columbia Gas System:

"Once the field has been selected and secured, and found by study to be a closed sand reservoir and if all of the wells are properly equipped, there can be no appreciable loss of stored gas and, furthermore, native gas in varying amount, acting as a safety factor, is still present in the reservoirs. Furthermore, these reservoirs held the original gas for almost countless ages and no change has taken place that would alter the physical reservoir in any way except the drilling of wells into it. . . . There is every reason to believe that if the casing and tubing of wells in the storage fields have been properly cemented and packed the pressures in the sand could be raised substantially above the original."

Discussions with other geological and operating personnel have indicated similar belief.

Yes, within the industry we have assured ourselves that the gas inventory is safe; but the investment in stored gas is growing and the ownership of natural gas securities is widespread. The factors that have convinced those within the industry that our underground savings banks are safe today, and will continue to be so, must be presented in the most effective manner for the benefit of investors, bankers, and auditors who are not as familiar with natural gas operations as we are.

That is one of the operating aspects of gas storage accounting, namely the development by operating personnel of all possible data confirming the safety of the gas in the ground.

The second point has to do with the periodic determination of the quantity of gas in the storage fields. Geologists have been making estimates of the volumes of gas in the native gas fields for a good many years. The re-

†Presented before American Gas Association, Natural Gas Department, Dallas, Texas, May 7, and 8, 1951.

*Assistant treasurer, Columbia Engineering Corporation.

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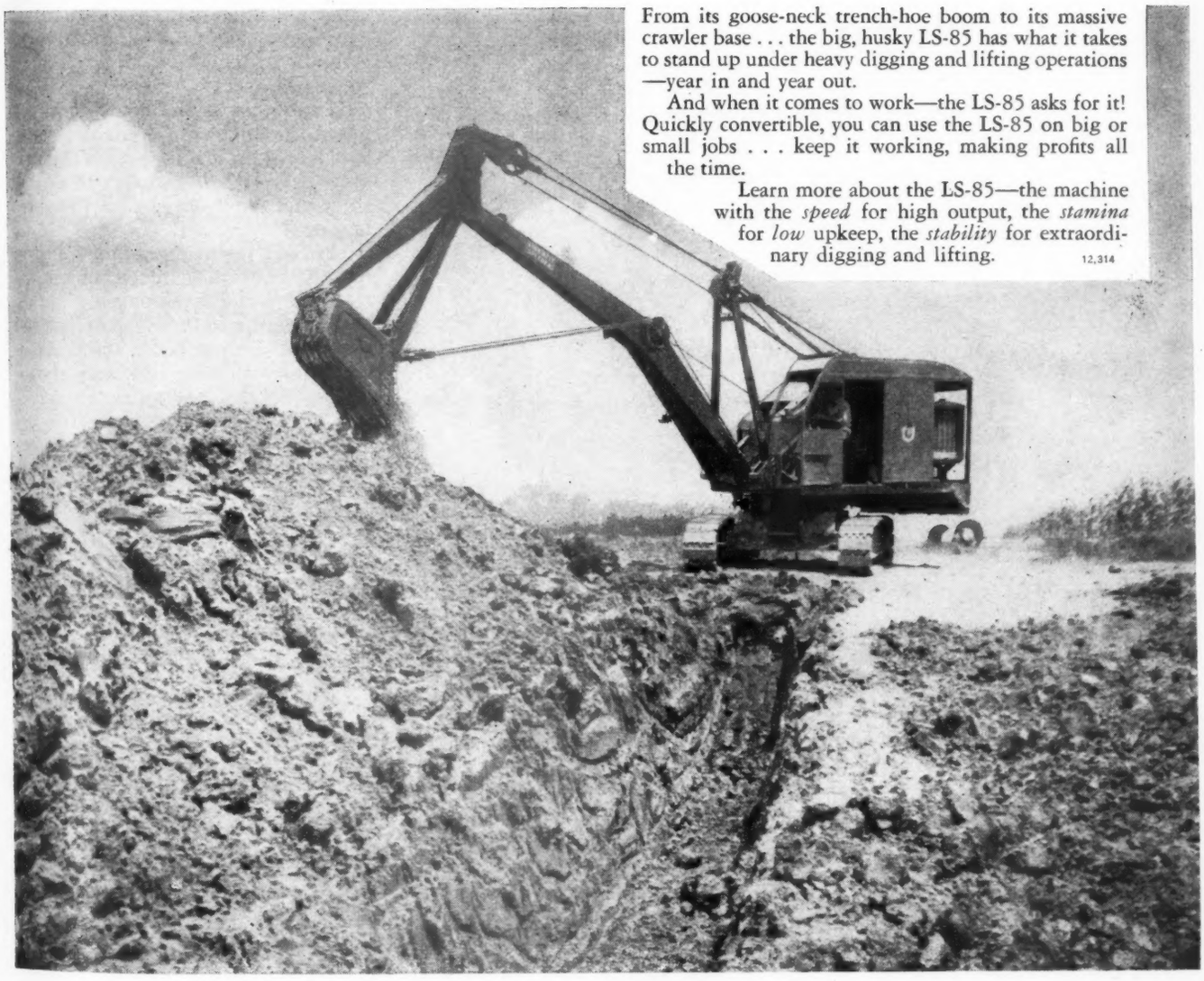

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sults to date have generally proved such estimates reasonably sound.

The recovery of gas in a native gas field, however, has a cost relationship only to the dollar invested for leaseholds and wells, and this investment is written off as the native gas is removed. This removal happens only once. In the case of a field with say 10 billion cubic feet of native gas and a property cost of say 6 cents per million cubic feet, the investment in the field would approximate $600,000. That is the sum total of the money that must be recovered with the exhaustion of the gas.

Let us take the same field and convert it to storage with an annual input and output of 3 billion cubic feet. If this is Southwest gas carried to distant storage fields, it would probably cost about 20 cents per thousand cubic feet. If the field is used for 30 years with that annual input and output, 90 billion cubic feet will move in and out of the field and the gas handled by it will cost $18,000,000 or more. It can readily be seen that the compounding of a minor error over that many annual turnovers can add up to a sizable sum of money.

This illustrates, I believe, the importance of the development of the very soundest methods for computing the volume of gas in our storage inventories. This is true, notwithstanding the added difficulties of making such determinations because of variations in input or output conditions in advance of rock pressure readings, such as additional well drilling, well cleaning, length of resting period, and others.

With so many dollars involved, our auditors must have maximum assurance to aid them in certifying our statements, and those who invest in our securities are entitled to similar assurance.

Many of you will recall the missing Canadian warehouse and drug inventory in the McKesson and Robbins case of a few years ago. The circumstances surrounding that case afford ample justification for the auditor's insistence on tangible evidence of the actual physical existence of the property reflected on the books.

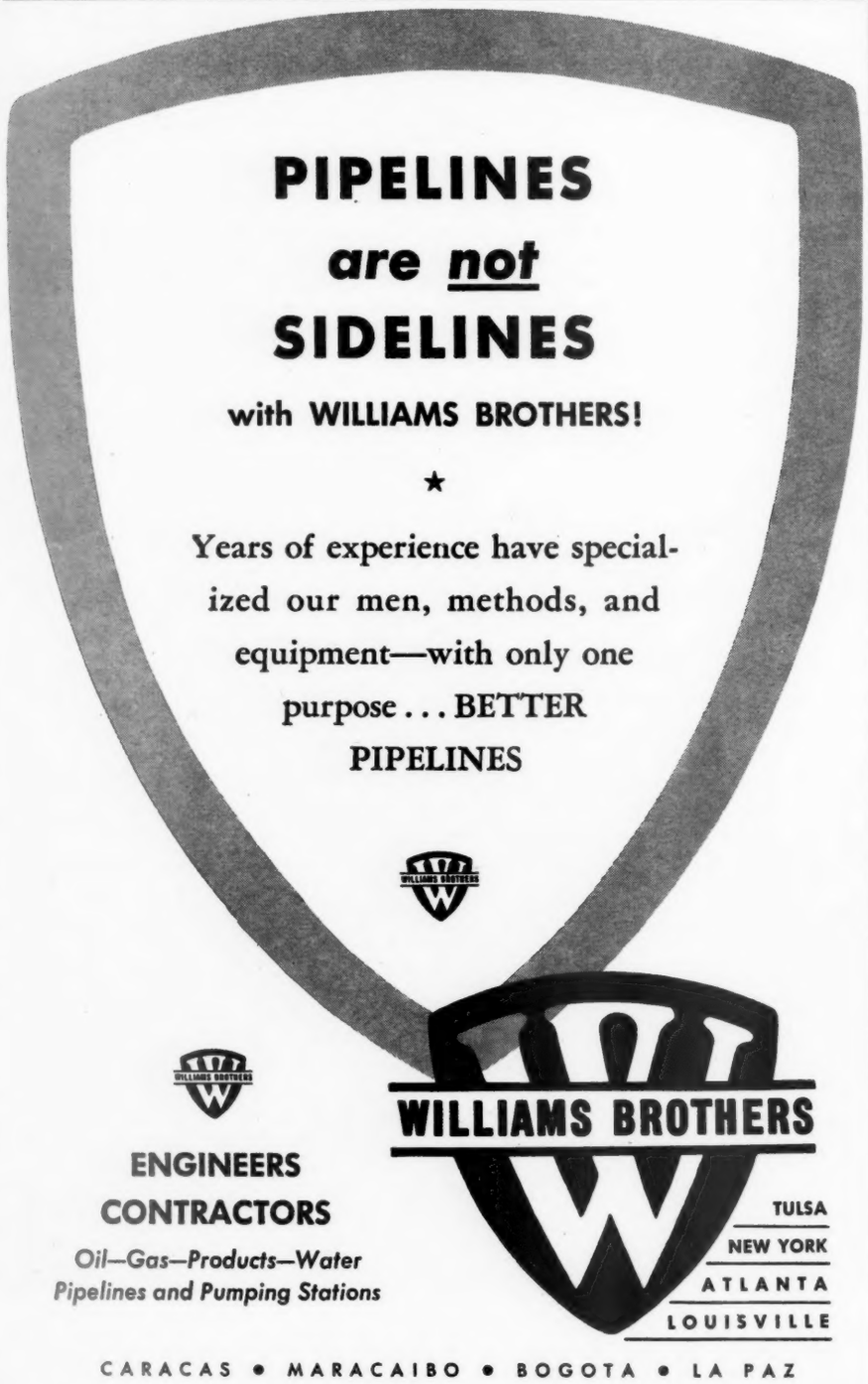
Therefore, it is maintained that close attention should be paid to the development of the best methods of determining the volume of stored gas actually in a given pool at a given time, and operating personnel should gear their use of the fields in such a manner that they are available periodically for the making of such determinations. It is not enough to merely show that the average rock pressures in a pool are so and so or that the delivery from the field per pound lost in rock pressure is so much, unless the net result is the development of an inventory figure in thousand cubic feet, which can be matched within reasonable limits with the inventory shown on the books.

That is another of the operating aspects of gas storage accounting, namely, the development of the best methods of determining the volume of gas in each of the storage pools as of given dates.

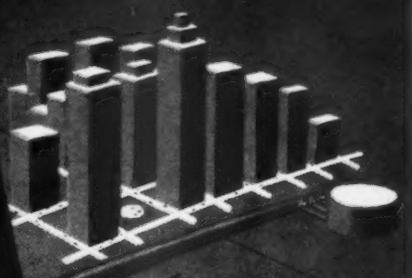
Recording Withdrawals

The third point has to do with the recording of all storage withdrawals or losses. A recent survey indicated not less than 12 ways gas might leave a storage field other than through a correctly measuring meter. There are probably others not in the list. All of these 12 ways are of such character that the loss or use is known by the operating personnel as it occurs, and the volume can be measured or accurately estimated.

Assuming the development by the geologists of the very soundest methods of determining the volume of stored gas in a pool, companies with extensive storage operations may be faced with some pretty substantial periodic inventory adjustments if these losses or uses are not recorded as they occur. The list includes:



WORLD'S LARGEST GAS PIPELINE SYSTEM SPECIFIES W-K-M VALVES



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(a) Blowing wells and drips.
(b) Gas used by free gas customers in storage areas.
(c) Gas used to pay gas customers in storage areas.
(d) Gas lost in drilling.
(e) Gas used in drilling.
(f) Well or line blowups.
(g) Gas lost in repairs to wells.
(h) Inaccuracies of measurement.
(i) Filling and purging lines connecting new wells and lines.
(j) Opening frozen lines.
(k) Loss of gas from storage fields to company owned producing wells and not accounted for as storage.
(l) Gas used by storage compressor stations in back of the measurement meter.

There are other types of losses, such as line loss or well leakage, which may not be determinable as they occur. These we may have to make inventory adjustments for as inventories are taken. The amount of such adjustments can be minimized, however, and the balance in storage as of any given date stated more accurately, if known losses or uses are accounted for as they occur.

To accomplish this, operating personnel should carefully report known losses or uses currently, and the volumes involved should be recorded as withdrawals of the gas.

This is a third operating aspect of gas storage accounting, namely, the current identification and reporting of known losses or uses of gas from the storage inventory.

As of the first of 1951, the Federal Power Commission adopted some revisions of its Classification of Accounts, the principal change being the inclusion of accounts and instructions for underground gas storage. The instructions for the inventory account include the following:

"As of the balance sheet date this account shall be segregated so that there shall be retained in this account only such amount as represents cost of gas appropriately classifiable as a currrent asset according to conventional rules of classification of current assets, not exceeding the estimated withdrawals of gas from storage for purposes of sale within the succeeding 24-month period from the date of the balance sheet."

The intent of this provision is amply clear—the gas storage inventory shall be divided between that part which is to be removed currently and that which it is intended shall be left in the ground for pressure purposes, usually referred to as cushion gas. Although some companies have been following this practice on their own for a year or two, the regulation is so new that some will be faced with the problem for the first time this year.

The classification intends that the inventory cost of the gas representing the base volume or cushion shall be transferred to fixed capital. The cost of the remaining volume, which it is expected will be available for current delivery, is to be retained in the current asset accounts.

In a substantially depleted field that is converted to storage operations, the cushion will consist of stored gas to a large extent.

In a pool that is only partially depleted when devoted to storage, stored gas may constitute only part or none of the cushion.

It is the job of the operating personnel to advise the accountant regarding the proportion of the total stored gas inventory that should be transferred to fixed capital. In developing your recommendation it is strongly urged that an allowance be made for abnormally heavy withdrawals so that the balance retained in the current asset category will be sufficient to handle the winter's delivery without encroaching on the volumes that have been transferred to fixed capital.

This is a fourth operating aspect of gas storage accounting, namely, a

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careful approach by the operating personnel as to the segregation between current and cushion gas in the storage inventory.

The fifth and last point involves the segregation of operating expenses between storage and non-storage. This point does not involve any action on the part of the operating personnel. Instead it has to do with explaining the thinking in back of some accounting policies that some operating men occasionally complain about.

The terms of the revised Federal Power Commission classification provide that the only property that shall be considered as storage plant is that which is used wholly or predominantly for the storage of gas. The terms of the expense accounts provide that the only expenses that shall be treated as storage expenses are those incurred in operating these storage plant facilities, and none of the costs of getting the gas to the storage fields shall be so treated.

The usual complaint runs something like this. "Well how is that fair? I am operating my compressor stations (substitute transmission lines if you wish) all summer long pumping gas to storage, yet I am charged with the whole cost. Why isn't that a storage expense?"

Well that is a logical question, however, it does call for a little analysis. During the several years that the cushion in a storage field is being established, maximum justice would probably dictate that you should be relieved of some of that cost. Cushion gas is not going to market.

On the other hand, the storage pool in almost every case will be closer to market than the original source of the gas. A good many storage pools have their own compressor stations, which do the pumping into the pool against existing rock pressure. Such costs are charged to storage expenses. Once in the ground the cushion gas has the effect of permanent horsepower in a place close to market and without doubt reduces future pumping costs.

Where the gas pumped is not cushion gas, but instead is annual input and output gas, pumping in the summer is merely reducing the pumping in the winter, and, as a better load factor is obtained, ultimate pumping costs are probably less.

There are other aspects of gas storage accounting that might be worth discussing, but time will not permit going into them.

If the points already covered can contribute to a better understanding of the joint needs of both operating and accounting personnel, the overall interest of the corporate enterprise and of the industry will be served.

* * *

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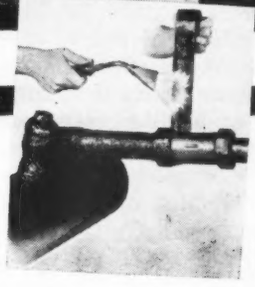

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A Portable Automatic Sampler*

W. E. ROADS†

KNOWLEDGE of certain physical and chemical characteristics of crude oil is essential to the efficient movement of crude oil via pipe line. Properties such as gravity, viscosity, vapor pressure, sulfur and hydrogen sulfide content, and BS&W content directly affect pipe line operations. These, and additional data such as ASTM distillations, product yield determinations, and detailed chemical analyses are of value to the refineries in their processing of the crude oils; but before any of this information can be determined, it is necessary first to procure a representative sample of the particular crude in question. Due to stratification within crude oil storage tanks, the test samples are best obtained from a sample connection on the pipe line, where a small portion of the crude can be bled off as it flows past the sampling point.

The ideal representative sample would be a continuous sample whose rate is directly proportional to the rate-of-flow through the pipe line, and whose constituents and percentages thereof, are exactly the same as those of the crude in the flowing stream. This ideal sample would be collected and stored at line pressure. Samples that approach the ideal may be obtained either manually or automatically, each method having its particular application.

Manual sampling is satisfactory in cases where the sampling period is of short duration, or where there are only slight variations in the characteristics of the flowing crude. This type sampling is also used to detect the interface between adjacent batches of crude oils. For this purpose sampling at frequent intervals is started slightly in advance of the scheduled arrival of the new batch. The gravity of each individual sample is immediately determined by means of a hydrometer—a significant change in gravity being an indication of a batch change.

For most other purposes automatic sampling is preferable to manual sampling from the standpoint of the reliability of results obtained from various tests run on the sample, as automatic sampling usually provides a more nearly representative sample than does manual sampling. There are a number of automatic samplers on the market that can be connected to a positive displacement meter such that a definite quantity of sample is taken per unit volume of oil flowing through the meter, thus collecting a sample that is proportional to the flow-rate through the pine line. The quantity per unit volume may be varied at the discretion of the user. If a positive displacement meter is not available, these same samplers may be connected through an electric time-cycle-controller, thus taking a constant-rate sample. Only where the rate-of-flow through the pipe line is essentially constant will constant-rate sampling give truly representative samples. Most of these samplers are of the intermittent type; that is, they take small "slugs" of oil during a short portion of their cycle, and take no sample at all during the remainder of the cycle. The length of the cycle varies from a few seconds to several minutes, depending upon the manufacturer's design and the conditions of operation.

The automatic sampler with which we are concerned here, is a special purpose sampler designed to take a series of samples throughout a large pipe line system. These samples were to be taken at small field gathering stations and at junctions where field lines inject into main trunk lines, as well as at trunk line pump stations. The following requisites were considered in developing the sampler:

A. Some samples would be taken at locations where neither electricity nor compressed air is available; consequently, the sampler must be completely self-contained—relying on no external source of power for its operation.

B. Sample periods of from one week to one month were anticipated. The size of the sample container had been established at approximately 10-gal capacity. This required sampling rates of from 1 cc to 4 cc per minute.

C. The samplers were to be used on a system-wide basis, so they must be portable and easily installed. A sampler would remain at a particular location for a maximum of 30 days, after which it would be shipped to another sampling point.

D. Samples would be taken from the pipe line at various pressures, the pressure varying from about 10 psig in some cases to as much as 1000 psig in others.

E. Water displacement sampling had been specified.

F. The nature of the data to be obtained from the samples was such that constant-rate sampling would suffice. In the majority of applications the rate-of-flow through the pipe line would be essentially constant; thus constant rate sampling would give representative samples.

With these requisites in mind the development of the sampler was begun. Original intent was to connect the oil-inlet side of the sample container directly to the sample tap on the pipe line, and to control the flow of water from the container, assuming that 1 cc of erude oil would enter the container to replace each cc of water that was displaced therefrom. Control on the water-outlet side would be obtained through the use of a pressure reducing valve, a diaphragm control valve, and a flow-control needle valve. This arrangement would keep the sample at line pressure and prevent vaporization of the light ends in the crude; however, it would require the sample container to withstand full line pressure, resulting in a very heavy and expensive container for 1000 psig operation. In order to save weight and cost of fabrication the sample containers were designed for a working pressure of 50 psig, necessitating pressure reduction between the pipe line connection and the sample container. In order to insure satisfactory operation of the pressure reducing and pressure control valves, filtering of the crude would be required. Filtering would remove a portion of the BS content from the sample; however, this was not considered objectionable since BS determinations

*Presented before The American Society of Mechanical Engineers, Petroleum Mechanical Engineering Conference, New Orleans, Louisiana, September 24-28.

†Engineer, Service Pipe Line Company.

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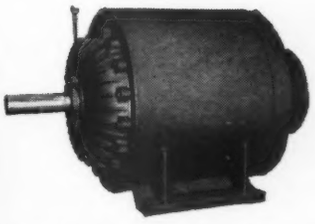

Construction used up to 800 hp, 3600 rpm.

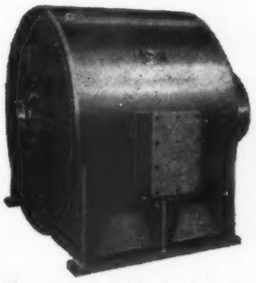

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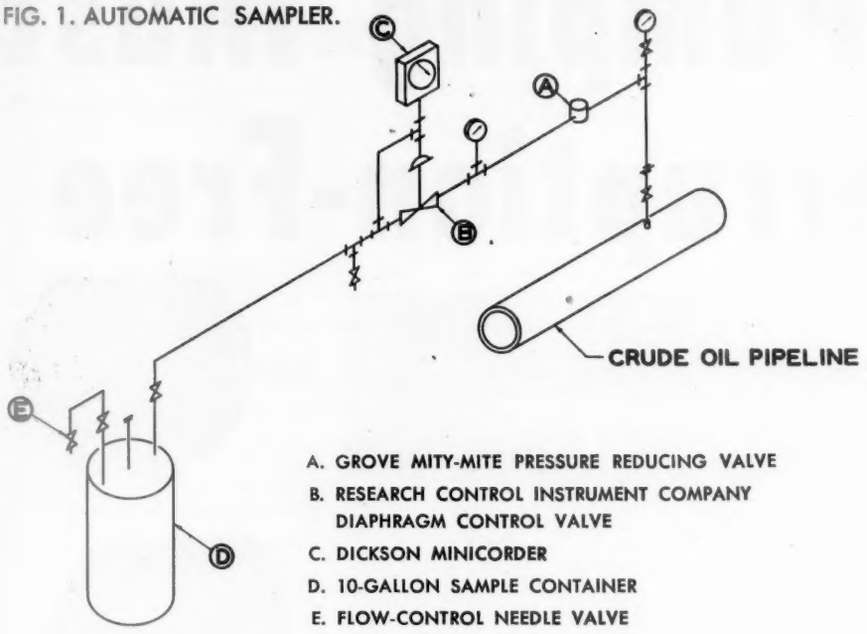
FIG. 1. AUTOMATIC SAMPLER.



A. GROVE MITY-MITE PRESSURE REDUCING VALVE
B. RESEARCH CONTROL INSTRUMENT COMPANY DIAPHRAGM CONTROL VALVE
C. DICKSON MINICORDER
D. 10-GALLON SAMPLE CONTAINER
E. FLOW-CONTROL NEEDLE VALVE

were not of primary interest in the crude analysis to be made.

Fig. 1 shows the sampler in its original form. It consisted of the following major components:

A. ¼-in. Grove model 94-WC Mity-Mite liquid pressure reducing valve with built-in 80-mesh screen wire strainer.

B. ¼-in. Research Control Instrument Company type 75 -diaphragm control valve.

C. Dickson type 3 Minicorder, range 0-15 psig.

D. 10-gal sample container.

E. ¼-in. flow-control needle valve on the water-outlet connection of the sample container.

In January, 1950, this sampler was connected to the scraper trap on a trunk station discharge line that was operating at 750 psig. As the tests were conducted during the winter months, a mixture of 50 per cent alcohol in water was used as the medium to be displaced from the sample container, the alcohol being added to prevent freezing. With a line pressure of 750 psig the Grove valve was adjusted to give a reduced pressure of 100 psig, and the diaphragm control valve was adjusted for a controlled pressure of 15 psig. The ¼-in. flow-control needle valve was adjusted for a flow-rate of 1 cc per minute; however, within 10 minutes the rate had decreased to ½ cc per minute. Within an hour the flow stopped completely. An examination revealed the accumulation of a fine, rust-like material inside the needle valve. Apparently this material was being carried in suspension in the alcohol-water mixture. An improvised chamois skin filter was inserted between the water-outlet connection and the ¼-in. flow-control needle valve. This proved to be a step in the right direction. Although the flow-rate decreased, it took 6 hr for the rate to change from 1 cc per minute to ½ cc per minute. Nevertheless this slowdown made it evident that the chamois was passing solid particles of sufficient size to lodge in the valve. In an effort to find a valve with larger clearances at low rates of flow, numerous other types were tried without success. During the interim, the chamois filter became almost completely clogged with foreign matter.

The chamois skin was replaced with 120-mesh screen wire, and the flow-control valve was replaced by a 10-in. length of 1/16-in. OD by 0.008-in. ID copper capillary tubing. For the first 5 hr of operation there was no detectable slow-down; however, shortly thereafter the capillary tube became clogged, completely stopping the flow. Obviously the 120-mesh strainer was not filtering the water sufficiently; however, problems of a more serious nature were developing. During the second hour of operation with the capillary tube, the controlled pressure rose slightly, indicating that the diaphragm control valve had completely shut-off; however, water was still flowing from the tube at the set rate of 1 cc per minute. This indicated that the increase in pressure must have been caused by expansion of vapors and liquid within the sample container. In a liquid throttling process of the type employed, pressure reduction is accompanied by a temperature rise, resulting in vaporizing a portion of the light ends in the crude. A check into the expansion rate of water revealed that a temperature rise at the rate of 1 F in 20 minutes would cause a flow of approximately 1 cc per minute from the 10-gal container with no flow into the container at all.

Thus, two factors that heretofore had been assumed to be of minor significance became of major importance. The accumulation of vapors made it apparent that either the container would have to be considerably larger in order to accommodate 10 gal of liquid crude plus the accumulated vapors, or the vapors would have to be vented to the atmosphere. In this particular instance a slight loss of light ends would not impair the samples, so venting was resorted to. This was accomplished by manually bleeding the vapors from the container once each 24 hr. Somewhat more difficult was the problem of nullifying the effect of liquid expansion and contraction due to temperature change. Maintaining the sample container at a constant temperature was thought to be impractical for a portable sampler of this type. The problem was solved by placing all the controls, including the capillary tube, on the oil-inlet side of the sample container, thereby leaving the container at atmospheric pressure. Thus, the crude oil would flow into the container at a constant rate regardless of the liquid expansion or contraction therein. A water reservoir was placed on the outlet connection of the sample container to prevent air from being drawn into the container due to contraction of the liquid.

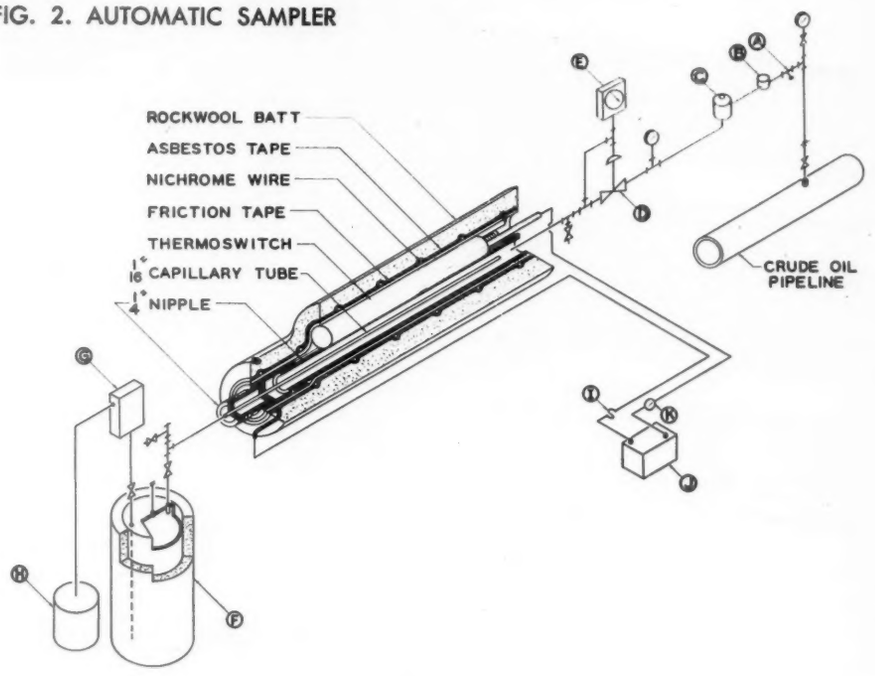
In changing the capillary tube to the oil side, the need for more adequate filtering and for temperature control was immediately apparent. In order to be assured of clean oil through the diaphragm control valve and the capillary tube, a Purolator fuel filter type D-7-9 with wire-wound filter element having 0.002-in. spacing, was placed between the Grove reducing valve and the diaphragm control valve. Changes in temperature have a marked effect on the viscosity of crude oil, which in turn greatly affects its flow character-

istics. For this reason temperature control was required. This was achieved in the following manner: A 10-in. length of 1/16-in. OD by 0.010-in. ID stainless steel capillary tubing was brazed into a ¼-in. by 1½-in. pipe nipple; about ½-in. of the capillary tube projected from one end of the nipple, with 8 in. projecting from the other end. The long end of the capillary tube was inserted in a ¼-in. by 12-in. nipple, and the two nipples were joined by a coupling (see Fig. 2). This assembly was then inserted in the piping between the outlet side of the diaphragm control valve and the oil-inlet side of the sample container. A Fenwal type 17000 Thermoswitch was then placed on the 12-in. nipple containing the capillary tube, and the entire assembly was wrapped with a layer of friction tape. Over this tape was wound an 18-in. length of No. 22 nichrome wire. The wire was connected through the Thermoswitch, a d-c ammeter, and a fuse to a 6-volt automobile-type storage battery. The Thermoswitch was adjusted to maintain a temperature of 100 F in order to keep crude paraffin in solution. Next, the entire capillary tube heating element assembly was wrapped with ⅛-in. asbestos tape followed by a 4-in. layer of rock wool.

The first overnight test run checked about 25 per cent short, based on the average of three 5-minute check runs made immediately prior to the test run. A check on the sample-rate at the end of the test run showed it to be exactly the same as it had been at the beginning of the run. However, an examination of the controlled pressure chart revealed a number of periods, approximately 15 minutes in length, during which the pressure had been somewhat above the normal control pressure. Apparently solid particles of sufficient size to lodge in the capillary tube were passing through the Purolator filter. These particles were evidently restricting, and possibly at times completely stopping the flow. In all probability the particles were being washed out of the tube from time to time, due to either the continued pressure differential across them, or partial melting from heat applied to the capillary tube.

The Purolator filter was replaced by a Fram type F-4 filter having a micronic paper element. In the past some difficulty had been experienced with the tendency of the Grove reducing valve to stick in the open position, so a ¾-in. Crane catalog No. 994-D "Y"-type strainer with a special 400-mesh monel element was inserted ahead of the Grove valve to alleviate this trouble.

FIG. 2. AUTOMATIC SAMPLER



A. CRANE "Y"-TYPE STRAINER
B. GROVE MITY-MITE PRESSURE REDUCING VALVE
C. FRAM OIL FILTER
D. RESEARCH CONTROL INSTRUMENT COMPANY DIAPHRAGM CONTROL VALVE
E. DICKSON MINICORDER
F. INSULATED 10-GALLON SAMPLE CONTAINER
G. WATER RESERVOIR
H. OVERFLOW CONTAINER
I. FUSE
J. 6-VOLT BATTERY
K. DC AMMETER

After these changes had been made, three more test runs were conducted. The first run of 20-hr duration checked 0.1 per cent short, the second run of 68-hr duration checked 13 per cent over, and the third run of 65-hr duration checked 6 per cent short. These percentage errors are based on the average of three 5-minute check runs made prior to each test run. The probable explanation of the apparent variation in the sample rates is that three 5-minute check runs are not sufficient to definitely establish the true sampling rate.

In all the test runs up to this point, the sample-rate had been approximately 1 cc per minute. The rate was increased to 3 cc per minute and a 7-day test was begun. Due to excessive current drain from the battery the Thermoswitch was adjusted to maintain a temperature of 65 F instead of 100 F. A 1-hr check run was made just prior to the 7-day run, and numerous other 1-hr check runs were conducted during the week-long test. At the conclusion of the test the volume of the accumulated composite sample checked 10 per cent short, based on the rate of the initial 1-hr check run. It is of interest to note that the amount of sample collected during each successive check run was slightly less than that of the previous check run. It is felt that this slowdown was caused by the very gradual accumulation of paraffin inside the capillary tube. The major portion of the 10 per cent error was attributed to paraffin. Samples were to be taken during the late spring, summer, and early fall, so no difficulty was anticipated in maintaining temperatures high enough to keep all the paraffin in solution. As time was short, no further tests were conducted. It was felt that the sampler had attained a sufficient degree of perfection to function satisfactorily under actual operating conditions.

Fig. 2 shows this special sampler in its final form. Ten of these units have been fabricated and put in service; and, although no definite performance data are yet available, it is felt that the samplers are operating well within 10 per cent of their set rate.

The flow-rate through the capillary tube will remain constant as long as the dimensions of the capillary tube, the pressure drop across the capillary tube, and the viscosity and gravity of the crude oil flowing through the capillary tube all remain constant. This is the principle on which the sampler operates. Maintaining a constant temperature within the capillary tube holds its dimensions constant,

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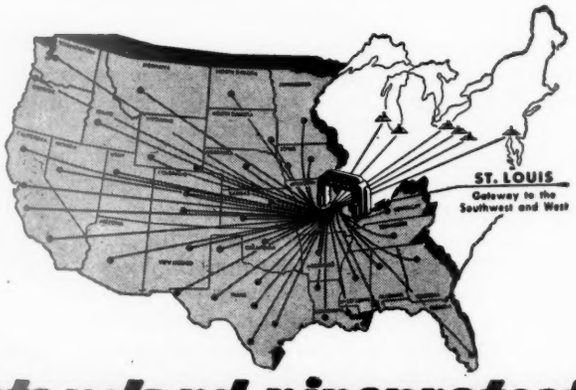

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and also keeps the viscosity and gravity of the sample crude constant, provided these two characteristics of the crude flowing through the pipe line do not vary appreciably. Maintaining a constant controlled pressure on one side of the capillary tube and atmospheric pressure on the other side provides a constant pressure drop across the tube.

As with all other pieces of mechanical equipment, this sampler has certain limitations, and must be operated within them. These limitations are:

A. BS&W determinations cannot be made due to the required filtering of the crude, and the water displacement method of collecting the sample.

B. A portion of the light ends in the crude is lost to the atmosphere because of continued venting. These light ends are vaporized due to pressure reduction and the addition of heat. The seriousness of this loss is questionable, as the majority of these vapors would probably be lost in tankage anyway.

C. Marked variations in the viscosity of the crude oil flowing through the pipe line will cause appreciable variations in the sample-rate.

D. Since for a given crude the sample-rate is essentially constant, the composite sample thus obtained will be proportional to flow-rate only when the rate-of-flow through the pipe line is constant.

E. Adjustments for large variations in sample-rate are difficult to make. A major change in sample-rate necessitates a change in the length of the capillary tube, or the installation of a different diaphragm spring in the control valve, either of which is a rather difficult job. On the other hand adjustments for slight changes in sample rate are comparatively easy to make. A change in the tension adjustment of the spring in the diaphragm control valve is all that is necessary. Changing the temperature setting of the Thermoswitch will change the sample-rate, but this method is not recommended. The Thermoswitch should normally be set at whichever of the following temperatures is the higher:

1. The lowest temperature at which it is certain that all the crude oil will remain in solution.
2. The maximum temperature that the sampler piping is likely to reach during the hottest part of the day.

Using the higher of these two temperatures prevents paraffin accumu-

1 REFINE IT with Self-Propelled Cranes

At the refinery, a Lorain Self-Propelled Crane is ideal for loading and unloading materials, construction and erection jobs plus any other material handling duty. It has 4 speeds up to 7 m.p.h., is air steered and available in several types and sizes.

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Tacaguan Pipe Line Proves Economical

Purpose of the Tacagua products pipe line connecting Caracas and the seaport terminal at Catia de la Mar is to lower the transportation cost of bringing petroleum products into Caracas. In his paper, *Some Technical Aspects of the Tacagua Products Pipe Line*, I. V. Tullar reported to the Third World Petroleum Congress that compared costs prove the Tacaguan line will yield a large saving.

Design of the line incorporates the latest safety and labor saving devices, and several alternatives were studied before the final plans were drawn. The pumps are kept operating, and shut down during emergency, by an automatic control system. Pumps are similarly protected from overheating or loss of pressure due to a line failure, Tullar, Creole Petroleum Company, reported. Should the lubricating oil system fail, or if for some other reason the engines overheat, they will be automatically shut off.

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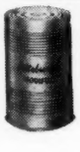

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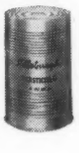

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lation, assures constant temperature operation throughout the sampling period, and prolongs battery life, which at best is about two weeks. Higher temperatures than this cut battery life drastically and increase evaporation losses.

To offset these limitations the sampler has the following advantages to offer:

A. It is portable, easily fabricated, and easily installed.

B. It is completely self-contained, requiring no external connections to a source of power. This allows sampling at any location where the crude oil is flowing under pressure.

C. The sampler continuously bleeds crude oil from the pipe line; thus a small portion of all the crude flowing past the sample connection is collected in the sample container. Continuous automatic sampling has a slight theoretical advantage over intermittent automatic sampling.

D. It is adaptable to taking very small samples over comparatively long periods of time. It operates satisfactorily at sample-rates as low as 1cc per minute.

E. All component parts required for its fabrication are readily available.

A slight change in design would make BS determinations possible. This would involve the removal of the sample container from its present location in the sampler piping, and its insertion between the sample tap on the pipe line and the Grove pressure reducing valve. With this arrangement only water would flow through the pressure reducing valve, the diaphragm control valve, and the capillary tube; consequently filtering of the crude oil would not be required. This modification in design would eliminate the possibility of paraffin accumulating in the capillary tube. It would also eliminate variations in sample-rate due to changes in the viscosity of the flowing crude. As was pointed out earlier in this paper, such an arrangement would require the sample container to withstand full line pressure. The container should be well insulated in order to minimize changes in sample rate due to temperature change. As the sample container would be at line pressure, it is felt that the quantity of accumulated vapors would be negligible.

Although this sampler has certain limitations, it is well suited for taking samples at remote pipe line locations, as the only requirement for its operations is that the crude oil be flowing under pressure in the pipe line. It has adequately fulfilled the purpose for which it was designed.

* * *

Design of an Unattended Automatic Booster Station*

Cost of building is about same as for attended station and economy is effected in operation

J. P. HEDLIN†

FIG. 1.

STANDARD OIL COMPANY (Indiana), one of the principal stockholders of Wyco Pipe Line Company, has recently supervised the construction of an unattended automatic booster station on Wyco's products pipe line from Casper, Wyoming, to Denver Colorado. This accomplishment is in itself a pioneer effort for our pipe line engineers and may be, to the best of our knowledge, a first in the industry. As this station has been in operation only a short time, since July, 1950, no overall operating and maintenance experience is available to date; however, the station was given a rigorous series of trial runs and it functioned as designed.

The author has reason to believe that the pipe line industry in general is more than mildly interested in unattended automatic booster stations. In these times of rising operating costs, it is becoming necessary for the industry, in general, to provide more service at less cost to maintain its competitive position, hence the entrance of the unattended automatic pumping station. This type of station has an economic advantage over its predecessor (the attended station) however, the question of economy through the use of unattended automatic stations should be examined for each individual case.

In our case, a small station of only 250 hp, it was found that the total cost of the station as built was no greater and possibly less than the cost of a similar attended station. These savings were realized because of economies in the building, the heating plant, and the foundations, which offset the added expenditures for the necessary automatic equipment. In the design of this station, the sole purpose of the building is to protect the operating equipment from the weather. This design principle precludes, therefore, the necessary facilities that are required at an attended station. The result is a simple prefabricated steel structure.

As the station is unattended, we have eliminated the heating plant, the water well, and other facilities that are required at a station where personnel is required on duty. This has also effected a savings. Because of the type pump used, which will be explained later, an appreciable savings was also effected in the foundations. This station also has the advantage over a conventional type station of realizing a saving of approximately $20,000 to $25,000 per year in operating labor. As a result of these facts it is evident that in this case the unattended automatic station had marked advantage over fully manned station.

The primary considerations in the design of an unattended automatic booster station are the pumping equipment and the controlling devices. The basic requirement of the pumps is that they can be operated without danger of an external product leak in the event of a gland (or seal) failure. The pump that meets this requirement is the stuffingboxless type. As the motor and pump are completely enclosed in a pressure-tight bolted case, the stuffingbox and packing have been eliminated. This does away with the principal cause for operational attendance and maintenance such as required by conventional pumps having stuffingboxes and packing.

One of the salient features in this type pump is the mechanical seal between the motor and the pump. The motor, including its bearings, operates completely submerged in an enclosed pressure chamber filled with transformer oil, which is used for the dual purpose of insulation and lubrication. Leakage across the mechanical seal is so regulated that it occurs only from the motor side to the pump side, preventing any product from leaking into the motor casing. This is accomplished by the transformer oil at a higher pressure than the product suction pressure at all times when the pump is in operation. While the unit is shut down the pressures in the pump case and the motor case are equal, and under these conditions the spring tension on the mechanical seal prevents leaking from the pump side to the motor side. To protect the pumps, a pump diaphragm switch is installed in each pump to shut down the unit automatically when the reserve supply of motor insulating and cooling oil approaches depletion.

To date these units have been manufactured in only the 125-hp size, which has obviously limited the size of fully automatic stations. One prominent pump manufacturer has indicated a willingness to manufacture this type of pump up to and including the 400-hp size. The reluctance of manufacturers to produce this pump in large sizes was based on the difficulty of cooling the motor. Until a reasonable demand is created for stuffingboxless pumps in sizes over 125 hp, the price will be high since the manufacturers will have to offset their cost for research and engineering.

The unattended automatic booster station constructed by our engineers is a two unit, 250-hp station capable of pumping 18,500 bbl per day of 0.73 specific gravity gasoline at a pressure of 215 psi per unit or a total of 430 psi for both units. The station was named Bear Creek and its location can be seen in Fig. 1. This station incorporates a control system for complete automatic operation of the pumps in accordance with the setting of a master control switch, which can be set for either one unit, two units, or no units operating depending upon the desired line throughput. It is essentially a pressure controlled station and will pump so long as the upstream station supplies sufficient pressure.

In Fig. 2 we have shown the profile for the Wyco Line. Normally the pro-

*Presented before American Petroleum Institute, Products Pipe Line Technology Conference, St. Louis, Missouri, September 11-13, 1950.

†Engineer, Standard Oil Company (Ind.), Products Pipe Line Department.

file would not assume any great importance in the operation of a pumping station; however, in the case of Bear Creek station, the profile cannot be overlooked. It will be noted from an examination of the profile that the static head on Bear Creek station is 500 psi (gasoline). As one unit of this station can develop a shutdown head of only 315 psi (gasoline), which in itself is not sufficient to overcome the static head, it is readily apparent that some provision must be made to prevent the pumps from spinning and as a result overheating. This problem was solved by installing a mercury pressure switch on the discharge side of the station. This pressure switch is set to open at 530 psi and close at 700 psi. This means that when the discharge pressure with the station operating drops to 530 psi, the switch will open and shut down the station. The station will remain inoperative until the pressure as supplied by the upstream station rises to 700 psi, at which time the switch will close and place the station in operation.

Fig. 3 shows a diagrammatic view of the station piping. It will be noted from an inspection of the piping arrangement that the pumps have been installed in such a manner that when not in operation, flow is directed through the pump sump and the check valve bypass. The divider gates are in the main line, which necessitates shutting down the station, and opening these gate valves whenever scrapers are run; however, runs are so infrequent that this procedure imposes no serious problem. The strainer shown is only a coarse mesh of four openings per inch.

It will be noted from Fig. 3 that

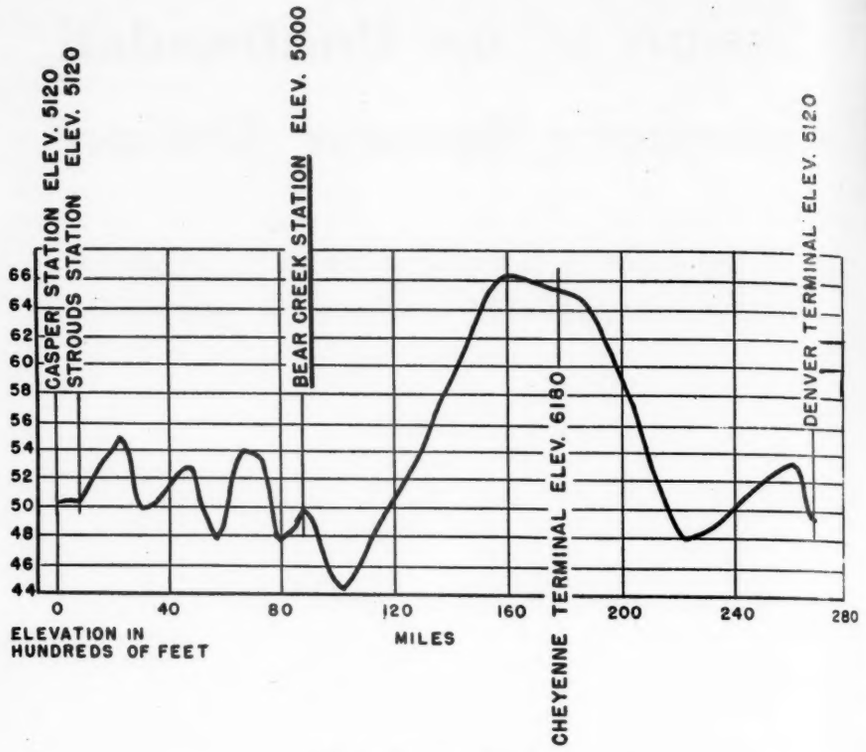
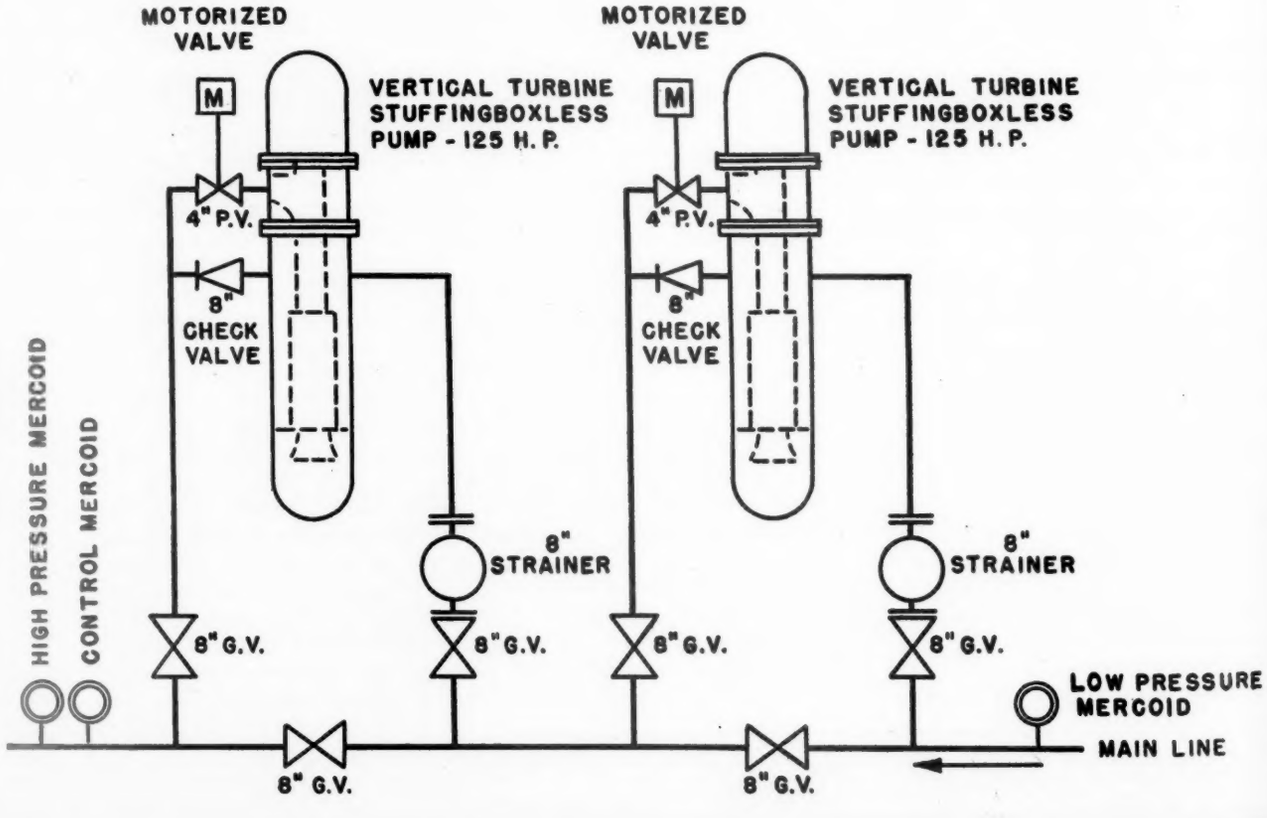


FIG. 2. Wyco pipe line.

FIG. 3. Flow diagram—Bear Creek station.



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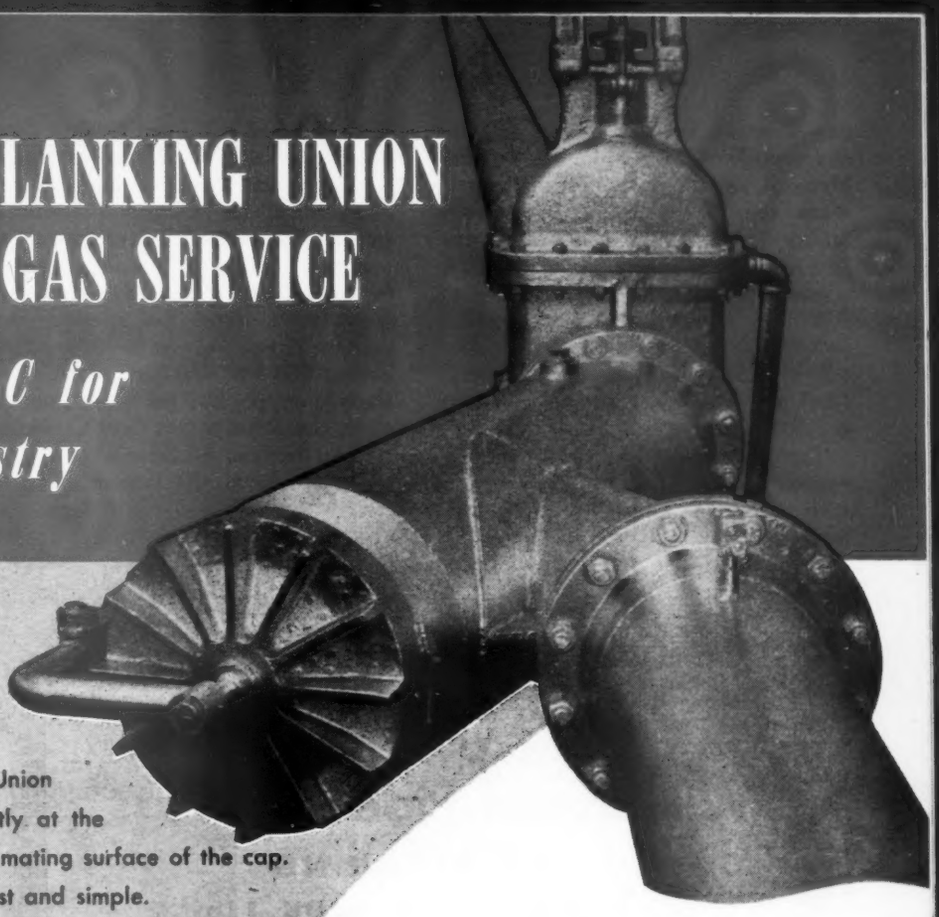

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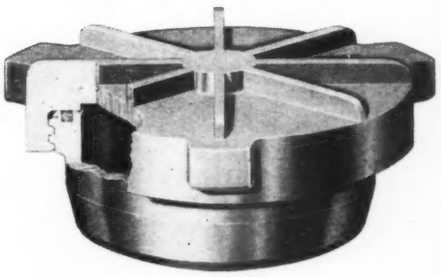
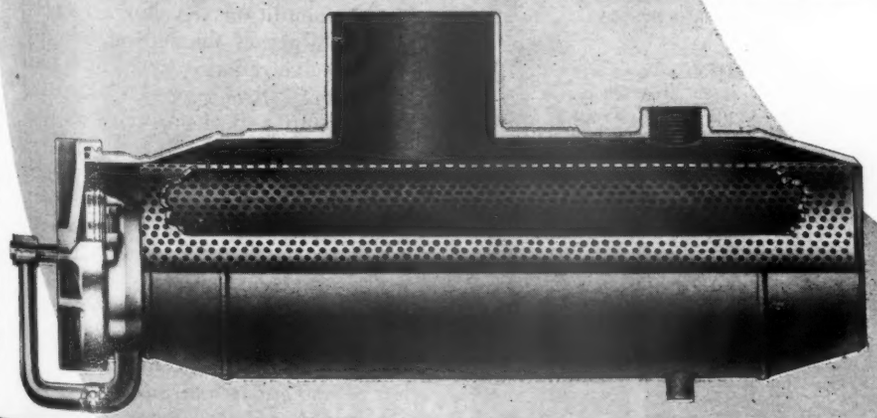
Typical installation of Yale Blanking Plug Union on C-R-C Horizontal "Across-the-line" Strainer. Available in sizes from 4" to 36".



The Yale Blanking Plug Union for gas blowdown valve installations. This union is much lower in cost and much easier to operate than flanges or any other type of quick-opening union.



Cross section of C-R-C Horizontal Strainer showing Yale Union installation. Available in sizes from 4" to 36".

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two Mercoids are installed on the discharge side of the station. The control Mercoid, as previously explained, prevents the discharge pressure from falling below hill pressure with one unit operating. The one labeled "high pressure Mercoid" is installed to shut down the station when the discharge pressure exceeds the maximum allowable operating line pressure; namely, 1200 psi. This Mercoid is set to trip at 1220 psi.

The low pressure Mercoid on the suction side of the station is set to open at 200 psi and close at 700 psi. When two units are operating and the upstream station is shut down, the suction Mercoid will open to shut down Bear Creek station. When one unit is operating and the upstream station is shut down, the minimum discharge pressure is reached before the suction pressure reaches its minimum, therefore, the control Mercoid stops the station. Reset of the low pressure and control Mercoids is set at 700 psi. This means that the upstream station will have to supply 200 psi more than the static condition to put Bear Creek station on the line. All three of these controls are electrically connected in series, which requires all of them to be in a closed position for the station to operate.

When the station is set for operation and sufficient pressure is present to close the control Mercoid and the low pressure Mercoid, the first unit will start. Simultaneously with the starting of the pump, the motor operated discharge valve begins to open. The motor-operated discharge valve takes 45 sec to reach the full open position and as it approaches its full open position, the bypass check valve is closed due to the differential pressure created by the pump. As a safety feature, we have installed a delay timer that will shut down the unit if the motor operated valve does not reach its full open position in one minute and 15 sec. This device was designed to prevent the pump from running against a closed valve, which might happen if the motor-operated valve failed to open. When a unit stops, the control wiring is so arranged that the motor operated valves will close; however, in the event of a failure, the motor-operated valve will remain open until power is restored. If this condition develops; namely, power failure at the station, the discharge valve remains open, flow then is automatically directed through the pump sump and check valve as previously shown in Fig. 3.

As an added safety feature, each unit has an incomplete sequence relay installed in its control wiring. This relay prevents the pump from attempting to start again if it failed to complete its starting cycle for any reason. For instance, if the motor-operated valve failed to reach its full open position in one and a quarter minutes the unit would stop and the valve would close. The incomplete sequence relay would prevent the unit from attempting to start again until manually reset.

"Invasion" Pipe Tested

Aluminum invasion pipe, first cousin of aluminum irrigation pipe, has just finished its basic training in Uncle Sam's Army. Army engineers and Aluminum Company of America have completed tests of aluminum invasion pipe to determine the suitability of aluminum pipe lines for carrying fuel, oil, and water to operation areas of a mobile army and an emergency-based air force. Advantages of aluminum invasion pipe seemed to be: Rapid laying of pipe line, ease in transport of fluids, reduction of the traffic problem in a congested battle area; conservation of fuel and, most important, its light weight.

THE PIG WITH THE POKE — CLEANS PIPE LINES

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Williamson Pipe Line Pigs*

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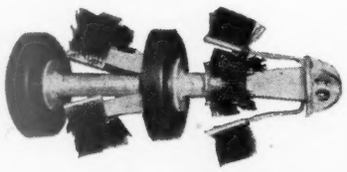
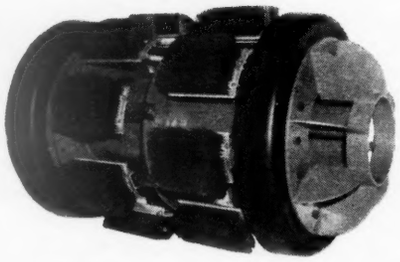
4" Size—TYPE JRN—2" to 4" sizes will pass 1½ R-90° Bends. No valves other than full diameter thru port valves.

Use TYPE SCN-51 for 6" size.



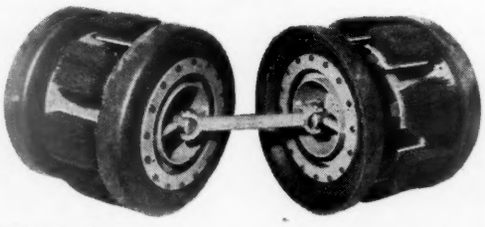
8" Size—TYPE WC-11—8" to 14" will traverse 6 foot radius field bends, full diameter side openings at 45°.

SPRINGS COMPENSATE for BRUSH WEAR.



20" Size—TYPE GP-2—16" to 30" 200 lb. SPRING forces the brushes against pipe wall—COMPENSATING for WEAR. Will traverse round opening gate or plug valves.

SPRINGS and BRUSHES are identical and interchangeable for all types and sizes of GP-PIGS.



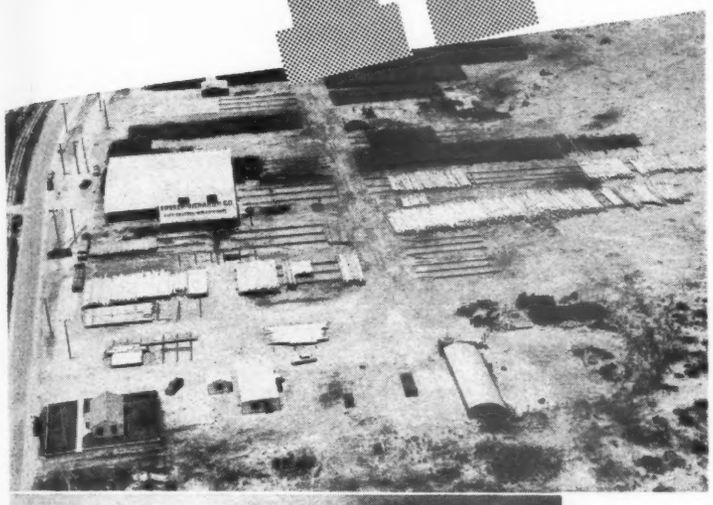
24" Size—GP-3—18" to 30" sizes will pass 1½ R-30° bends. SPRINGS COMPENSATE for BRUSH WEAR ASSURING full section cleaning efficiency. GP-3 consists of two Type GP-1 Pigs. Each unit may be used as individual pig.

*Patents Pending

T. D. Williamson, Inc.

TULSA 9, OKLAHOMA

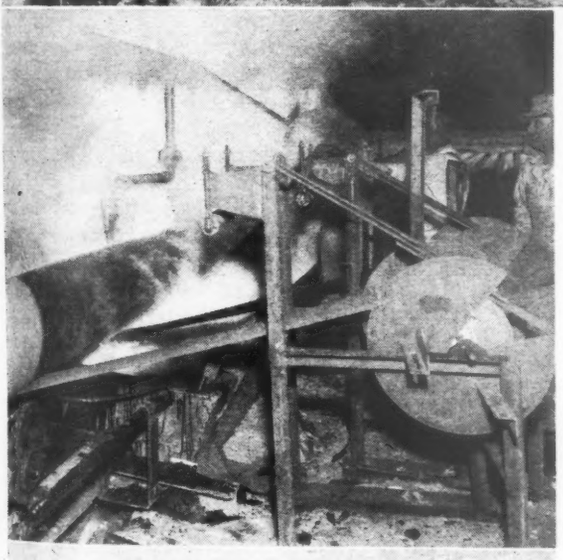
Rosson-Richards



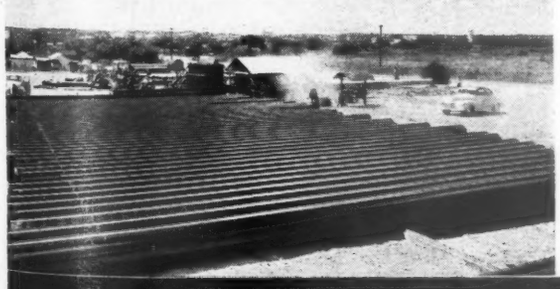
WRAPS, COATS and WATE-KOTES line pipe for protection and weighting

Wherever pipe coating and wrapping are to be done, Rosson-Richards is prepared to move in and do the work right on the job—with the proper equipment, the trained men and the technical "know-how." Rosson-Richards Companies have had years of practical experience behind them—assuring you of highest quality workmanship.

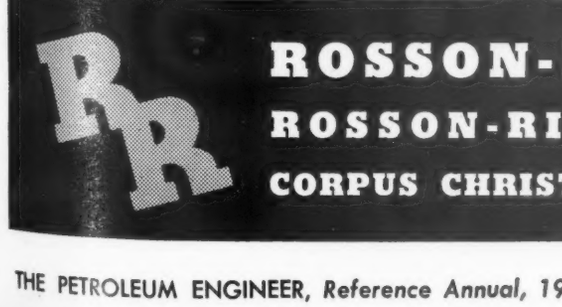
If pipe is to be laid in water, swamps, or in rivers, WATE-KOTE—the Rosson-Richards high-density, high-strength pipe coating—is the answer. WATE-KOTE was developed by the Rosson-Richards Processing Company.



A. The Rosson-Richards Pipe Coating and Wrapping Plant at Corpus Christi, Texas.



B. The WATE-KOTING machine in operation. WATE-KOTE is "sprayed" onto the pipe by means of high-speed belts at high impact velocity to obtain maximum compaction.



C. 30" primed pipe ready for coating and wrapping.

Advantages of WATE-KOTE

1. **Extremely high bulk density.**
2. **The compressive strength of WATE-KOTE is nearly double that of ordinary concrete and consequently WATE-KOTE is far less apt to be damaged while transporting, stacking and handling.**
3. **WATE-KOTE is not affected by waters of high alkalinity or acidity.**
4. **WATE-KOTE requires only a 48-hour curing period, thus permitting faster installation of the coated pipe.**
5. **WATE-KOTE machines are portable and can be set up near the actual job, thereby eliminating the cost of shipping heavy coated pipe.**
6. **WATE-KOTE may be used on thin wall pipe to gain the necessary weight, rather than using a heavy-wall pipe. This results in savings in steel and pipe costs and welding.**
7. **With WATE-KOTE the weight is distributed over the entire length of pipe and not concentrated at certain points, such as is the case where cast iron or concrete river clamps are used.**

ROSSON-RICHARDS COMPANY
ROSSON-RICHARDS PROCESSING CO.
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Each pump unit has under voltage time delay relays that will prevent the unit from being shut down due to momentary voltage dips. This relay will trip two seconds after voltage failure. A voltage dip will cause the motor starter to drop out and stop the motor, but if voltage is restored within two seconds, it will start again without going through a complete shutdown and starting sequence.

If the second pump is to be used it will start 10 min after the first pump starts and in the same sequence. This delay between the starting of units allows the first unit ample time to load up and accelerate the stream. The pumps are started across the line with 440-volt oil-immersed combination starters with solenoid operated contactors. Each motor feed circuit is connected to an open and reverse phase relay, which trips when the power supply reverses phase or has one of its phases open. The action of either relay will shut down both units.

To assist the operating personnel, a series of graphs similar to the one shown in Fig. 4, which is for gasoline, was constructed. These graphs relate the discharge pressure at the origin station (Strouds) to the volume pumped by the station. Referring to Fig. 4, it will be noted that three groups of curves each containing three curves were plotted. The three groups are: No units operating at Bear Creek, one unit operating at Bear Creek, and two units operating at Bear Creek. The three curves in each group represent the two extremes and the average for the terminal receipts. The value of this curve to the operator lies in the fact that for any given pumping rate, number of units operating at Bear Creek, and terminal delivery, he can quickly determine his discharge pressure at the origin station. From the dispatcher's point of view, these graphs are invaluable in that for any required pumping rate and terminal delivery, he can predetermine and preset the number of units to be operated at Bear Creek during any month for a given tender of products.

Although this paper has been prepared without the benefit of an extended period of station operation, the design has served a definite purpose in providing additional capacity at a remote location and to date has proved entirely satisfactory. This installation may well be the prototype for similar improved pumping stations that will operate without personnel on duty.

The significance of this step cannot be ignored in view of the increasing high operating costs. ★ ★ ★

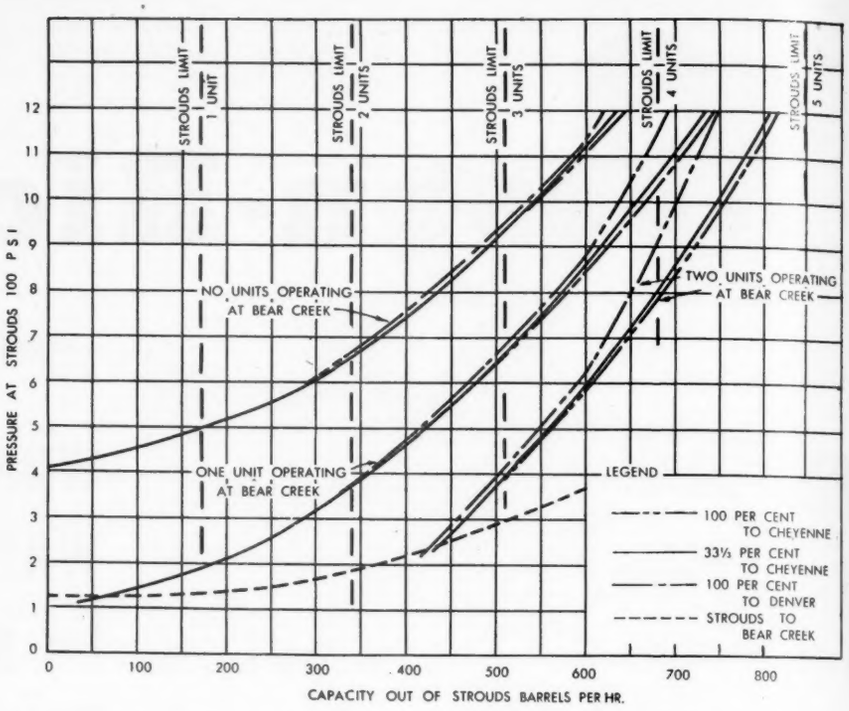


FIG. 4. Wyco capacity curve, Strouds to Cheyenne and Denver. Gasoline 60 API, .75 centistokes.

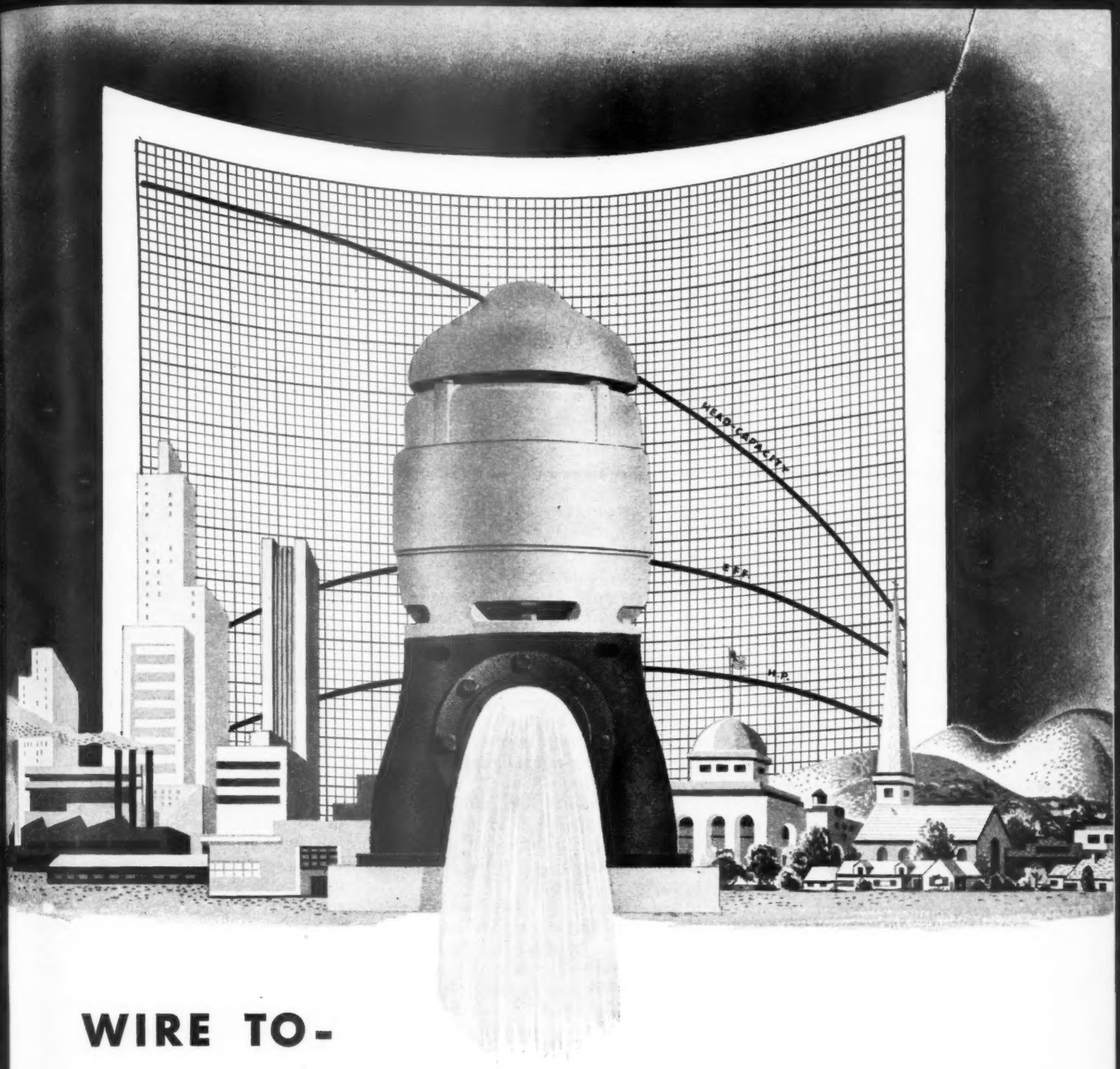
Gas Transportation Aided by High Strength Pipe

Installation of pipe lines of great length and capacity has been made feasible by development of large-diameter high-strength pipe, together with progress in welding and laying techniques, Paul E. Noll, Consolidated Western Steel Company, Los Angeles, California has reported. In his paper titled *Large-Diameter High-Strength Pipe for Oil and Gas Transmission,* given before the Third World Petroleum Congress, Noll reviewed the characteristics of available high-strength pipe and their relation to pipe line design.

Noll also discussed the means of increasing strength, and the characteristics and processes of manufacture of the most common type of high-strength pipe, namely expanded or cold-worked pipe.

The effect of expansion is examined, as affected by amount of deformation and chemical composition of the steel. Also described is an effective yield strength test of a section of pipe, in which incidental observations were made by means of a brittle coating. The importance of avoiding surface damage is emphasized.

Manufacture of large diameter high strength pipe is of major economic significance, the author believes, and adds that notable progress has already been made in its development.



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New and Suggested Techniques for Improving the Recovery of Oil†

PAUL D. TORREY*

Abstract

Great progress has been achieved during the past two decades in the development of methods for improving the efficiency of oil recovery. The record of past accomplishment encourages the belief that further progress may be anticipated as a result of continued research. Oil recovery research is devoted both to studies on methods for reducing production costs and on methods for the improvement of recovery efficiency. It has been estimated that a reduction of 1 per cent in the present recovery limit will add more than 1 billion barrels to the world's recoverable oil reserves.

The Bradford field, New York and Pennsylvania, is cited as an example of the successful application of secondary recovery methods, and of the opportunities that exist for the development of improved oil recovery technology. In this field the application of secondary methods has served to increase the primary recovery of oil by 1.7 times. However, it is known that some 750 million barrels of high grade crude oil will not be recovered by the secondary methods currently employed.

The equation of radial flow is presented, and its application to studies of methods which may improve oil recovery is discussed. The most impressive opportunities appear to lie in the control of permeability values and in the reduction of viscosity of the reservoir fluid.

Some of the methods that are being considered or are being applied in small scale field tests for the purpose of increasing the recovery of oil are listed as follows:

1. The Atlantic high pressure gas injection process, which is currently being employed in a pilot plant test in Crane County, Texas.

2. The injection of inert gases, which is being carried on in fields in Kansas and Wyoming, but which has not progressed sufficiently to provide dependable quantitative data.

3. The application of heat to reservoirs, which has interesting possibilities in connection with the underground gasification of coal.

4. The extraction of oil by solvents, which appears to be feasible where hydrocarbon solvents can be used and and where it is not necessary to separate completely the solvents from the crude oil in the field.

5. The combined injection of gas and water, which in the Bradford field indicates may result in an improvement in recovery of from 10 to 15 per cent.

6. Chemical flooding, which includes: (a) the use of surface active compounds to increase injective capacity and to increase oil recovery; (b) the important application of carbon dioxide, which in numerous laboratory tests and in one field test has indicated a notable increase in efficiency in oil recovery, and, (c) treatments designed to increase relative permeability to water in the reservoir at input wells and to increase the relative permeability to oil at producing wells.

7. The release of oil by bacteria, which up to the present has provided more information on the origin of oil than on the recovery of oil.

Promising possibilities have been indicated for some of these techniques, but it is impossible at the present time to evaluate completely their future application or their relative importance.

DURING the past two decades great progress has been achieved in the development of methods for improving the efficiency of oil recovery. Some of these improvements have been the result of accidental discovery, but the majority, in the writer's opinion, can be attributed to engineering research that is being continued by many oil companies and institutions of higher learning. The record of recent accomplishment provides promising encouragement that continued progress in oil recovery technology may be anticipated.

Oil recovery research currently receiving wide attention by the oil industry is devoted principally either to the development of methods for reducing production cost or to a search for new methods for the improvement of recovery efficiency. Reduction in cost may apply either to development or to operation. Improved recovery can result from any method successful in causing greater uniformity of fluid movement through hetereogeneous reservoirs or in a reduction in the residual oil content left in the reservoir at the time of abandonment after the application of the most effective methods now known.

There is rather general agreement that under most conditions the water drive and the gravity drainage producing mechanisms will yield a superior recovery of oil. Even under the most favorable conditions, however, these mechanisms leave unrecovered from 20 to 30 per cent of the total pore volume. Dr. Morris Muskat[1], one of the best informed authorities on oil reservoir behavior, has estimated that a reduction of 1 per cent in the present recovery limit will increase the world's recoverable oil reserve by more than 1 billion barrels.

Improved Oil Recovery Technology

A review of the recovery of oil from the Bradford field, New York and Pennsylvania, will serve to illustrate the magnitude of some of the oil reserves that have been obtained in the past and that may be obtained in the future by the application of improved recovery techniques.

The Bradford field is one of the world's largest oil fields producing

†Presented at the Second Oil Recovery Conference, A & M College of Texas, April 19-20, 1951.
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from one continuous reservoir. It covers some 85,000 acres on which have been drilled over 35,000 producing oil wells and around 18,000 water injection wells. Oil was discovered in the Bradford field in 1871, and the peak of primary production was reached in 1881 when almost 23,000,000 bbl of oil were obtained.

The total oil production from the Bradford field to the end of 1949 has been slightly over 524,000,000 bbl. Of this amount some 254,000,000 bbl are estimated to have resulted from primary production, and some 270,000,000 bbl have resulted from secondary production. It is estimated that the remaining secondary reserve of the field amounts to some 68,000,000 bbl and it is considered possible that an additional recovery of some 93,500,000 bbl may be obtained by improved production techniques such as higher injection pressures and the isolation of barren sand sections, and under a favorable crude price schedule. The oil recovery that may be obtained from the Bradford field as a result of secondary water flooding operations, therefore, may amount to some 431,500,000 bbl, which will mean that oil recovery will be increased by 1.7 times. Secondary water flooding will yield, it is believed, slightly over 5000 bbl per acre of additional oil for the entire area of the field, which compares with a primary recovery of slightly less than 3000 bbl of oil per acre.

Average reservoir conditions and oil recovery results obtained in the Bradford field are listed as follows:

	Per cent of pore volume
Estimated original connate water content	20
Estimated shrinkage	15
Estimated original oil content in place	65
Primary oil recovery by dissolved gas drive	15
Secondary oil recovery by water flooding	20
Residual oil content after water flooding	30

At the present time much of the Bradford field is in the final stages of secondary depletion, notwithstanding the fact that the reservoir contains a residual oil content of approximately 750,000,000 bbl of some of the most valuable crude oil in the United States.

The Equation of Radial Flow

Any consideration of methods for the improvement of oil recovery efficiency will benefit from a review of the factors that control the movement of fluids through porous rocks. The flow of oil through a porous reservoir to a well depends on the permeability of the formation to oil, the thickness of the formation, the viscosity of the oil, the distance that the oil must move to reach the well, the diameter of the well bore, and the pressure differential that is created while fluid is being produced. In a reservoir, where oil is flowing radially from all directions toward a well, the rate of flow may be calculated by the following equation:

$$Q = \frac{K \times 2\pi \times t(P_1 - P_2)}{\mu \times \text{Log}_e\ (r_1/r_2)} \quad (1)$$

Where:

- Q is the rate of flow of the oil in milliliters per second,
- K is the permeability of the rock in darcys,
- π is 3.1416,
- t is the thickness of the rock in centimeters,
- P_1 is the static or closed-in reservoir pressure in atmospheres,
- P_2 is the bottom-hole pressure in atmospheres when the well is flowing at rate Q,
- μ is the viscosity of the oil in centipoises,
- Log_e is the Naperian logarithm,
- r_1 is the radius of the drainage area in centimeters,
- r_2 is the radius of the well bore in centimeters.

It should be evident that the fluid flow equation can be applied either to a well producing fluids or to one receiving them. Actually it can be applied to the field operation of water injection wells with greater certainty than to a producing oil well, for a water injection well receives water only, whereas an oil well may be producing a composite mixture of oil, water, and gas that can render a laboratory determination of "K" to be meaningless. Also, in a producing oil well the value "r_1" may not be determined with precision because of geologic conditions, but for an injection well the average distance to which pressure effects may be extended outwardly through the reservoir can be calculated from a knowledge of the porosity of the formation, its fluid content, and the cumulative volume of water injected.

The control of the amount and rate of fluid injected in secondary recovery or pressure maintenance operations is very important to insure the maximum economic recovery of oil. To produce oil from a reservoir by secondary methods it must be displaced and moved largely by extraneous force. Similarly, in order to maintain pressure in fields possessing a substantial part of their original reservoir energy, but where expansion of free gas or encroachment of water may not be effective, fluid must be replaced as it is withdrawn. Control of the injection rate, therefore, is one of the factors that helps to control

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recovery. Various characteristics of the reservoir rock and of the reservoir fluid have a composite effect on fluid injection into oil-bearing rocks. These effects may be modified by the manner in which both input wells and producing wells are completed, by the manner in which they are equipped, by the pressure differential that is created, and by the manner in which oil and gas are withdrawn. These modifying effects can be controlled better by the operator than the inherent characteristics of the reservoir and the reservoir fluid.

Obviously, it will be impossible to alter geometric constants, the thickness of the reservoir, or the logarithmic value in the radial flow equation. Also, it may not be practical to reduce existing well spacing or to enlarge well bore diameters, and it is well known that the pressure differential that can be applied to any reservoir is limited definitely by the danger of pressure-parting of the formation or of bypassing of the injected fluid. Therefore, it will be apparent that the most promising opportunities for improvement in the rate of fluid movement and oil recovery should be found in the development of methods that will help to control permeability values and to reduce the viscosity of the reservoir fluid.

An increase in "K" will have a similar effect on rate of flow to an increase in the pressure differential. This is accomplished in present practice by the use of explosives, by the acid-treatment of carbonate reservoirs, and by a rupture of the rock resulting from the injection of a liquid possessing a very high viscosity. Both shooting and acid-treatment will tend to increase the well bore diameter, represented by the value "r_1". The horizontal effects of shooting and of hydrafrac treatment is to produce open fractures through which reservoir fluid may move to the well bore more effectively. In consequence, a general increase of the "K" value throughout tight sections of the reservoir will permit the movement of oil which, otherwise, would be impossible under the existing conditions of pressure differential. Such possibility is of tremendous importance in considering any plan to improve recovery from many of the thick carbonate reservoirs where it is very likely, under natural conditions, that only a minor fraction of the reservoir is making any substantial contribution to oil recovery.

It is certain that a reduction in crude viscosity will facilitate the rate of recovery. Whether the ultimate recovery will be improved is not known with certainty, but it is probable if the economics of recovery are considered. It is well known that highly viscous

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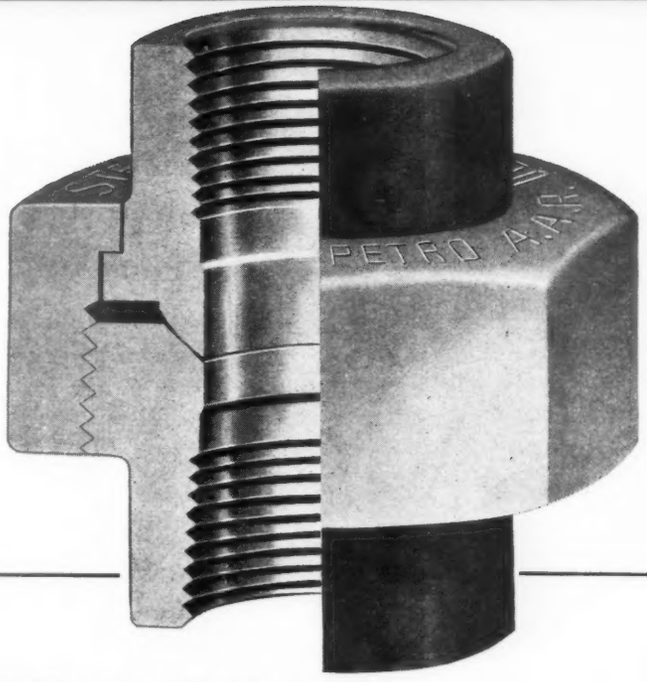

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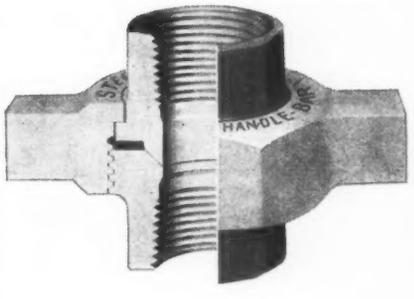

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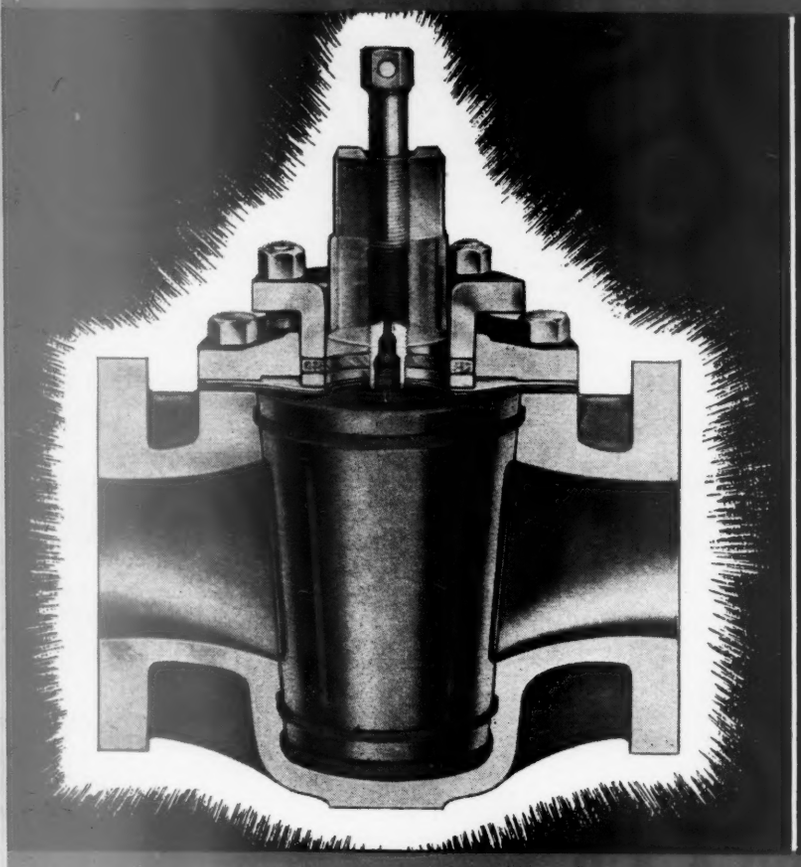

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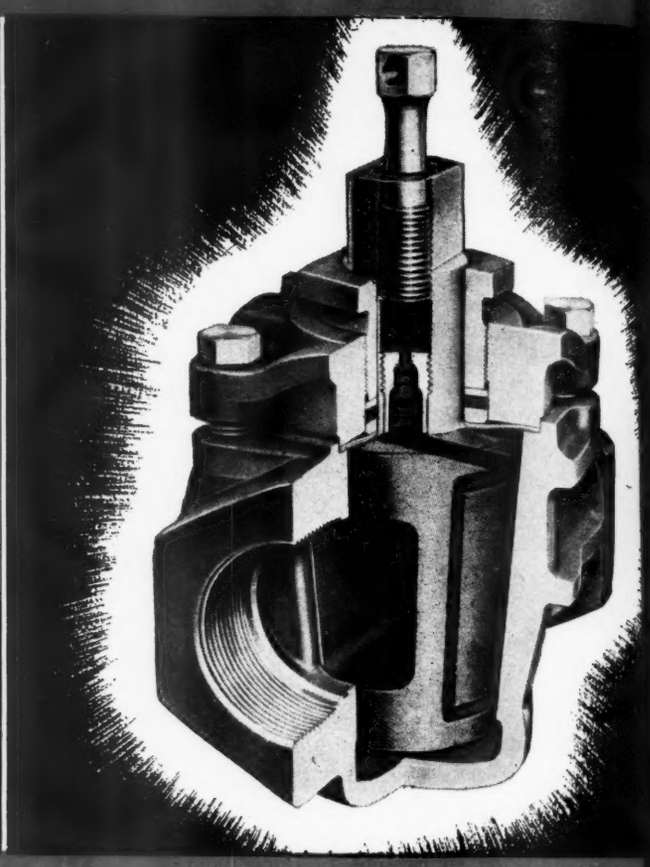

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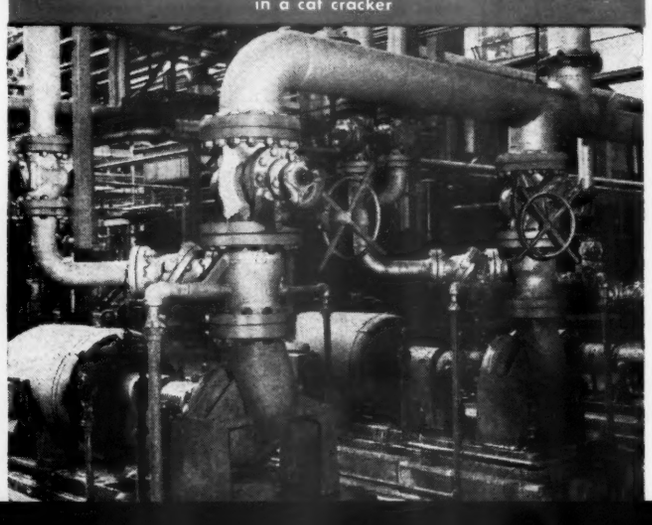

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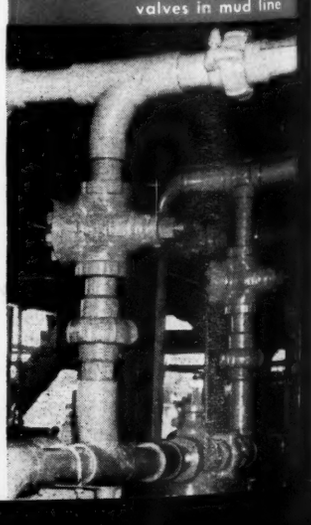

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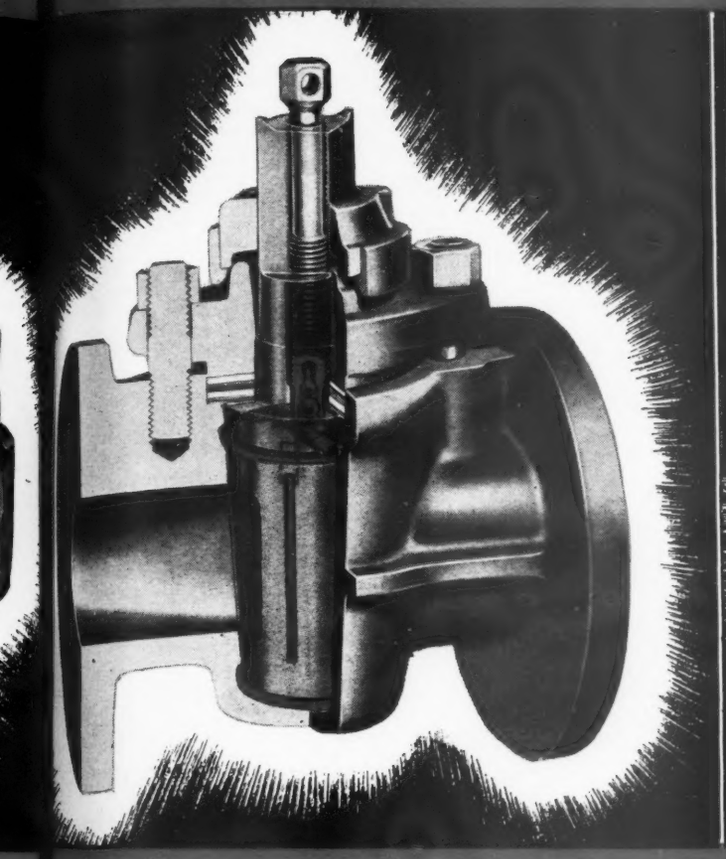

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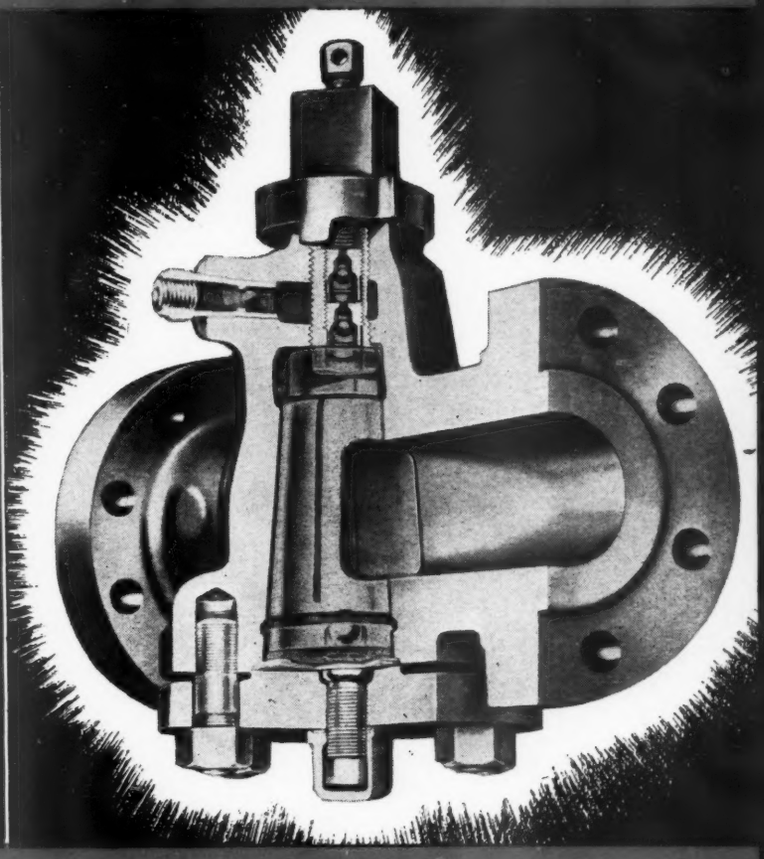

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oils may not respond successfully to pressure restoration systems as the amount of pressure required to move the oil at an economic rate will exceed the ability of the rock to withstand rupture. As a result, pressure parting will take place, which can destroy all desirable uniformity in the movement of the injected fluid.

High Pressure Gas Injection

During the past year (1950) reports of experimental work conducted by the production research department of the Atlantic Refining Company have indicated that reservoir crude viscosity may be decreased substantially by resaturation with light hydrocarbons at elevated pressures. Consideration of the equation of radial flow, as previously indicated, will show that a reduction in viscosity will benefit the rate of recovery, and particularly under conditions where a high pressure differential is maintained. Improvement in ultimate oil recovery has been indicated by a pilot plant field test currently (1951) in progress in Crane County, Texas. This test is regarded as being so successful that a large scale field operation will soon be undertaken.

The Atlantic process consists of the injection of large volumes of high pressure gas, containing substantial quantities of the intermediate hydrocarbons—ethane through heptane—which are required to produce desirable solubility effects. Pressures in excess of 3000 psi appear to be necessary from laboratory data to produce the desired effects, but it is believed that such pressures will not result in excessive bypassing because of more advantageous viscosity relations. Pressures in such range will probably restrict use of the process to the deeper reservoirs, however, where dangers from pressure parting phenomena are not so acute. Laboratory experiments indicate that improved oil recovery may be obtained because of:

a. the retrograde solubility effects that account for enrichment of the gas with intermediate boiling range hydrocarbons.
b. the subsequent solution of these intermediates in the "downstream" oil to a high volume, relative to the original.
c. the viscosity change as a result of enrichment of gas and swelling of oil. These viscosities are much closer together than occur in the virgin state, enhancing the displacement efficiency.

Promising possibilties for the successful application of the high-pressure gas injection process would seem to exist in the deeper reservoirs that possess sufficient strength and rigidity to withstand the indicated pressures.

Injection of Inert Gases

The injection of inert gases has been undertaken recently for pressure maintenance in fields where sufficient natural gas is not available or where air cannot be used successfully on account of corrosion problems. Elimination of oxygen, also, is considered desirable because of the reduction in the hazards of explosions.

In the Elk Basin, Wyoming field[3], where the injection of nitrogen was commenced in March 1949, the use of inert gas was decided to be necessary because of the shrinkage of the casing-head gas resulting from the removal of condensable hydrocarbons and from the removal of large quantities of hydrogen sulfide. The removal of these gases did not leave a sufficient residue of hydrocarbon gas to maintain pressure in the Tensleep reservoir at the desired rate of production. Other sources of natural gas supply were not available, and sufficient water could not be obtained for pressure maintenance purposes at reasonable cost.

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have been removed. In this operation the removal of the high content of hydrogen sulfide and its conversion to free sulfur is an important economic item. Because of lower solubility of nitrogen in the reservoir crude in comparison with methane and other light hydrocarbon gases, it is believed that the use of nitrogen for pressure maintenance may result in a better displacement of oil than would be the case if hydrocarbon gases were used exclusively. Field results are not sufficiently advanced to provide results that may be compared with similar operations where compressed natural gas is injected to maintain pressure.

Application of Heat

The application of heat to oil reservoirs has interesting possibilities, and various attempts have been made in the past to inject hot water or hot gases to reduce the viscosity of the crude oil or actually to vaporize it and to recover fractionated hydrocarbons at producing wells. None of these heating projects, as far as is known, have been successful due to high cost and to the deposition of carbon in the pore spaces of the reservoir resulting from the cracking of the crude oil molecules.

Recent laboratory experiments[4] have indicated that relative permeability of the reservoir to water may be increased permanently in some instances by over 200 per cent by temporary heating of the rock to a temperature of around 235 F under the moderate pressure. Thereafter, these tests have shown, the use of cold water may be commenced or resumed, as the case may be, with no loss of permeability to water. If field application of this heating process to water flooding operations should be effective in the manner that the laboratory work has indicated, the results will be of great economic significance. Increasing the relative permeability of the reservoir to water in the immediate periphery of the bore of the injection well, would permit a great increase in water injection rate with no increase in water pressure, thus preventing the possibility of pressure parting of the formation. Also, such change in relative permeability might remove the necessity for shooting the reservoir in injection wells.

The most fascinating possibility for the use of heat in the recovery of oil has been proposed during the past year (1950) by Frederick Squires[5]. Squires has noted that failure in previous reservoir heating experiments probably has been due to the small amount of heat that could be applied in proportion to the great bulk of the rock involved. From studies that he has made at the experimental underground coal gasification project of the Alabama Power Company and the Bureau of Mines, situated at Gorgas, Alabama, it has been found that some 10,000,000 cu ft of gas at a temperature of 1700 F are produced daily. In this operation it has been demonstrated that the volume of gas at this high temperature can be produced almost indefinitely. It has also been shown that the hot gas will move through permeable sandstones above the burning coal bed and that it can be brought to the surface through open holes that have been drilled through them. It is believed that if these sandstones had happened to have been oil-bearing rock most of the oil would have been brought to the open holes in the vapor phase.

Squires has noted that many of the oil-producing areas of the United States are situated in coal basins where the oil reservoir rocks are in reasonably close proximity to coal beds. He suggests that hot gases can be produced underground and injected directly into the oil reservoirs without first bringing the gas to the surface. The oil would be vaporized in large part by the high temperature, and would move to the producing wells and thence to the surface in the vapor phase where it could be recovered and partially refined.

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Another method whereby the viscosity of the reservoir crude might be reduced, and which might provide, in addition, a scrubbing action on the reservoir surface, is by the injection of solvents, either in the form of condensable gases or as liquids. The introduction of solvents could be followed by conventional gas or water injection.

The economic aspects of solvent extraction appear attractive in areas where low cost hydrocarbon solvents are available. Special means for separation of hydrocarbon solvents from the crude oil might not be necessary in all cases. Solvent present in the gas phase at the well head would be recoverable in connection with the usual processing of the separated gas. Solvent remaining in the crude oil could be recovered if required by a crude stabilization process. Hydrocarbon solvents remaining in the oil, however, should be marketable along with the crude. A large proportion of the injected solvent should be recoverable by direct displacement in reasonably uniform reservoir rocks, and losses by diffusion could be expected to be compensated by greater oil recovery. A final blow-down of the reservoir should release other portions of solvent temporarily blocked from flow streams.

Recalling the familiar technique in which samples of oil reservoir rocks are cleaned for various laboratory tests by solvent action, it could be expected that a high degree of recovery of oil might be obtained by this process.

High gravity crude oil, during a period of over-production, has been stored successfully in shallow California reservoirs that possess high permeability and that contain heavy, high viscosity crude that drains very slowly into wells. Subsequently, when an attempt was made to obtain the recovery of the high gravity oil, much more oil, of an intermediate gravity, was recovered than had been injected, and it was indicated that for the area effected by light crude injection, the recovery of the heavy oil had been improved substantially.

Beginning in 1929, when a plan for the unit operation of the Masjid-i-Sulaiman oil field was adopted, the Anglo-Iranian Oil Company, over a period of about 6 years, returned approximately 30,000,000 bbl of surplus refined products to the reservoir. These products — chiefly light tops, natural gasoline, and fuel oil—are accumulated at the refinery during periods of limited market demand, and are blended at the surface prior to injection. After several years of injection of refined products, it was found that they tend to diffuse in the crude oil remaining in the reservoir, and by so doing have been responsible for the recovery of substantial quantities of crude that, otherwise, would have been irrecoverable.

Combined Gas and Water Injection

Laboratory investigations[6] over a period of several years have shown that substantial improvement in oil recovery may be obtained by the injection of alternate volumes of water with gas. The improved recovery obtained by this process is produced in a shorter period and requires the injection of smaller quantities of gas. As might be expected, increase in the total liquid saturation in the reservoir will retard bypassing of injected gas and, thereby, should result in lower produced gas-oil ratios. Several field tests of alternating gas and water injection currently (1951) are in operation.

Several investigators[7,8] have reported that the presence of free gas in the reservoir has a beneficial effect on oil recovery by water flooding. The effect of the gas has been to produce lower residual oil saturations than could be obtained by flooding alone, and laboratory tests are reported to have shown an improvement in oil recovery of up to 50 per cent by the establishment of a free zone of high gas saturation in the reservoir prior to the injection of water. It is believed that the beneficial results obtained from prior gas injection are due to several factors, among which may be cited:

a. the occupation of space in the reservoir by gas that otherwise would be filled with residual oil.
b. an increase in mobility brought about by changes in the relative permeability values, and by a reduction in the viscosity of the reservoir crude.
c. a swelling of reservoir fluid as the result of solution of gas.
d. the selective filling of the more permeable sections of the reservoir with gas bubbles (the Jamin effect) ahead of the water thus reducing bypassing tendency of the injected water.

The South Penn Oil Company has been injecting natural gas into the oil reservoir of the Bradford field, Pennsylvania, on several of its properties for a period of over 10 years. This technique was adopted in part as a gas conservation measure to insure an adequate supply of fuel for production purposes over an extended period of time. South Penn does not consider the oil recovery effects obtained to date to be sufficiently conclusive to justify publication. It has released data[9], however, on one project situated in the southern part of the Bradford field where some gas had been injected over a period of 3 months into the sand after water had been going into the formation for several years. Thereafter, water injection was resumed in the normal manner. It has been estimated that oil recovery will be increased from 10 to 15 per cent by the combined water and gas injection over what would have been obtained by conventional flooding alone.

In 1944 Frederick Squires[10] first proposed secondary recovery by simultaneous injection of gas in the central part of a field possessing low structural relief, and the injection of water around the edge. He, also, proposed an ideal method of pressure maintenance for fields situated on well-defined anticlinal structures in which gas is injected in wells situated at the highest part of the structure and water is injected contemporaneously slightly below or at the existing water-oil contact. The method proposed by Squires first received a field test, as far as is known, in the West Tepetate field, Louisiana by the Barnsdall Oil Company (now Sunray Oil Corporation) where water injection was commenced in 1946 and gas injection was commenced in 1947. Results of significant importance have been obtained from this project, and it is indicated to be one of the most successful pressure maintenance projects in the United States.

Chemical Flooding

It has been known for some time that certain chemicals, particularly those possessing the property of reducing the surface tension of water, even at very low concentrations, will increase the recovery of oil in water flooding experiments. These compounds are referred to frequently as being "surface active" as a result of their behavior at a liquid surface. When they are mixed with water, their molecules exhibit the remarkable tendency of collecting at the contact between the liquid and a solid or between the liquid and a gas. Thus, when the normal surface of water molecules is replaced by these totally different groups of atoms, the physical relation between the water and anything with which it is in contact is changed radically.[11]

Artificial control of interfacial tension between water and oil by the use of surface tension depressants has so far failed in practical application because of the tendency of the chemical to be absorbed on the solid surface. The advancing water front, therefore, is depleted of these reagents before any beneficial effects can be realized. The amount of chemical that will be

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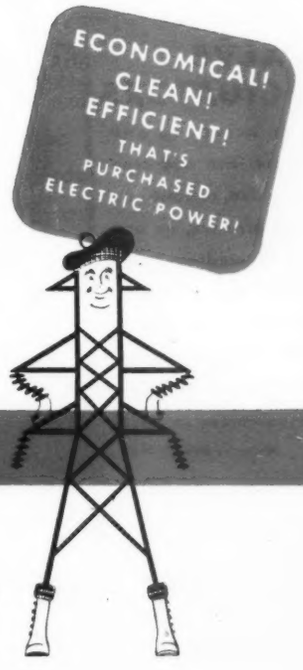

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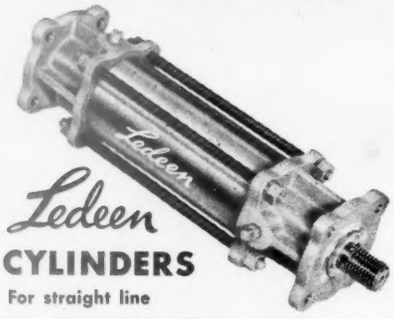

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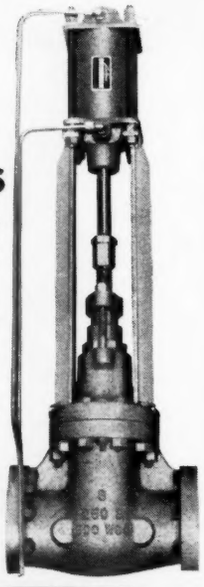

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required to provide for effective penetration of a reservoir and its cost has been, in consequence, entirely out of proportion to the value of the additional oil that might be obtained.

In recent years a group of surface active compounds, consisting of ethylene oxide condensations of fatty amines, have been developed by Armour and Company that show promising possibilities for use in connection with water injection operations.[12] These compounds, in laboratory tests, have shown very encouraging ability to retain their surface active properties after months of contact with pulverized oil sands. In other laboratory tests they have shown remarkable ability to reduce oil saturations to very low levels. In a current field test (1951) their use has increased the rate of underground fluid movement from input wells to producing wells substantially with no increase in injection pressure.

Use of Carbon Dioxide

Another promising chemical recovery process, that is receiving a field test in a watered-out area in Allegany County, New York, is the injection of carbon dioxide in water solution. Original discoveries on uses of carbon dioxide in solutions and mixtures as an aid to oil recovery have been made by James W. Martin[13] over a period of several years. Martin has discovered that under certain ideal conditions of pressure and temperature carbonic acid will react with some of the constituent compounds of crude oil to produce unstable solvents or surface active compounds, thereby causing certain parts of the oil to act as a solvent or displacing agent unto itself. When the fluid is brought to the surface and the pressure is reduced in a separator, these compounds in large part will break down into crude oil and the combined gas, which may be reused after it is separated from gaseous hydrocarbons. Laboratory tests have been successful in reducing oil saturations in reasonably homogeneous sands down to the low level of from 8 to 5 per cent of the total pore volume. Also, it has been indicated that the permeability of the reservoir rock to oil is increased, which can serve to increase the rate of oil recovery.

Some of the possibilities for the use of carbonic acid to improve the recovery of oil have been discussed recently by George Weber.[14] The current field test of the process in Allegany County, New York, has been in operation for about 18 months, during which time a production of oil has resulted that is 10 times greater than that obtained from adjacent flood units that are effected only by conventional water injection. The high recovery efficiency indicated by over 1000 laboratory flooding tests with carbonated water has been confirmed by engineering studies of the analyses of cores obtained from the area effected by the carbonic acid injection.

The results obtained to date from the use of carbonic acid encourage the belief that this process may be applied successfully to watered-out and marginal areas in the Penn Grade territory, and elsewhere. Currently, a carbonic acid injection project is being commenced under excellent control in a Bartlesville sand field of northeastern Oklahoma, and studies are in progress in the southwest to determine a promising field for an experimental injection of carbonic acid into a limestone or dolomite reservoir. Laboratory work indicates that the injection of carbonic acid may be particularly effective in carbonate reservoir rocks.

There is also the important and attractive possibility of changing relative permeability of the reservoir by some form of direct chemical treatment of the reservoir surface both at injection and producing wells. If, for instance, it should be possible to increase permeability to oil and to decrease correspondingly permeability to water, the economic possibilities for producing more oil profitably from a reservoir that has been depleted by conventional water flooding would be enhanced greatly. Such treatment might require penetration by the treating agent for only a few feet in the immediate periphery of the well bore of producing wells to result in a large reduction in the produced water-oil ratio. Similarly, an increase in relative permeability to water, as mentioned previously, in the injection wells should serve to improve materially the injectivity index with no increase in injection pressure and, very possibly, might eliminate the necessity for the use of explosives in input wells.

All measures for the control of relative permeability will require effective isolation of the horizons to be treated and, subsequently, to be produced. Valuable chemicals, and, in arid regions, water itself cannot be wasted by injection into zones where no benefit can be anticipated.

Release of Oil by Action of Bacteria

From laboratory work[15] it has been known for several years that certain bacteria will promote the release of hydrocarbon substances from rock surfaces. This is accomplished, so it is believed, by the creation of solvents that promote the separation of oil from the minerals making up sedimentary rocks, by the production of gases and surface active compounds

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that will assist in the removal of oil, or by the actual replacement of an attached oil film by swarms of micro-organisms. It has been suggested that cultures of various bacteria might be introduced into oil-bearing rocks to facilitate recovery. Up to the present time extensive experiments on the effects of bacterial action have been more useful in providing information on the possible origin of oil and gas than on how the efficiency of recovery may be improved. Laboratory tests have demonstrated the release of hydrocarbons by the action of bacteria from samples of Canadian tar sands. but as far as is known no recovery of crude oil has been obtained in the laboratory that would encourage the injection of bacteria cultures into oil reservoirs in connection with water flooding operations. However, the variety of bacteria available for test purposes are so extensive that research in the possible application of microbiology to oil recovery is being continued. Probably the most important factor effecting the possible use of micro-organisms in water flooding is the question of time. It would appear to be essential that the action of any culture would have to be sufficiently rapid to be adaptable to ordinary oil production practice.

Concluding Statement

Certain interesting new techniques for improving the efficiency of oil recovery have been considered in this paper. Promising possibilities have been indicated for some of these techniques in experimental and pilot-plant field tests, but it is impossible at this time to evaluate completely their future application or their relative importance. It is notable, however, that the results of extensive research and investigation indicate the probability that no single standardized technique will be developed that can be applied with equal success to all oil reservoirs. In so many cases differences in reservoir characteristics between fields are far more impressive than similarities. For that reason it should be emphasized that the recovery possibilities of each field should be considered from the standpoint of its own reservoir characteristics rather than from any apparent or suspected resemblance to others.

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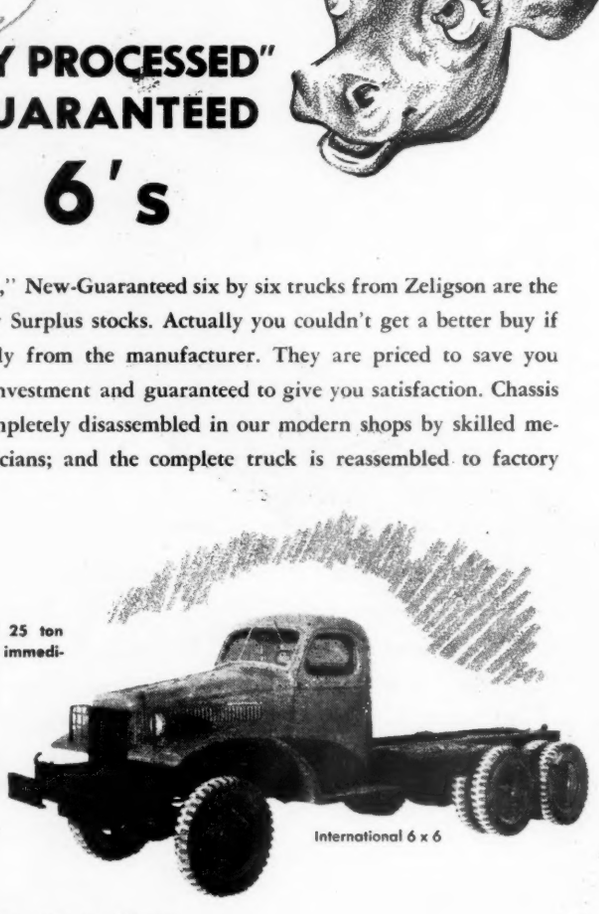

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Irrigation of farms, processing of foodstuffs, operation of air conditioning and refrigeration equipment, production of pharmaceuticals and medicines, power generation and, consequently, the overall industrial facility of the nation requires abundant, inexpensive, chemically clean, relatively cold water. In recent weeks much has been written concerning critical local shortages in water supply. The national press has carried front page copy describing the near-disastrous shortage in Metropolitan New York City resulting from decreased rainfall in the area. In recent years the effect of gradual declining underground water tables has focused attention on major industrial centers including Dayton, Toledo, Louisville, Peoria, and Chicago. In vast areas of the south and west, from the earliest days, water has been regarded as a limiting factor in industrial development.

An effort to confine our present discussion to the problem of industrial water conservation in the midwestern United States, directing particular attention to the involvement of the power industry, accentuates the complexity of the basic problem. Statistical data are rapidly being accumulated in usable form. Sources of collateral data are being tapped for pertinent facts. Although correlation may be difficult, concerted effort by all concerned will shorten the time required to effect satisfactory solutions. The power industry can well afford to take the lead, demonstrating by efficient, well-engineered applications that improved technology can avoid dissipation of a basic natural resource.

It is not appropriate that engineers quietly accept unqualified generalities such as "large chunks of our country are running out of water" or "in several areas water levels have dropped 55 ft in 6 years" or "the Louisville water table is down 40 ft in 10 years." We must develop accurate data coupled with intelligent analysis and specific recommendation. Federal agencies, state commissions, and local groups have become aware of the importance of industrial plant conservation measures. The active attack on the problem has already begun. Aggressive pursuit must follow. It is not good management to wastefully use water when invocation of water conservation methods can reduce the slope of the operating cost curve. Growth in demand load reflects directly the industrial growth and population increase of a geographical area. Without effective procedures for water conservation, the natural laws of diminishing returns are invoked. With but one common source of supply, the necessity of mutual approach to the problem is self-evident.

Omitting statistics from *new* plants built *during* the period of 1939 to 1949 it is apparent that the use of water by established basic industries in the midwestern area has increased over 40 per cent in the past decade. Of the total water consumption in the average large industrial plant 53 per cent is used for cooling, 31 per cent used in process, 8 per cent in boiler feed water, 5 per cent for sanitary purposes, and approximately 3 per cent for miscellaneous demand. In the major industries, *increases* in total water requirements are estimated for the 10-year period ending in 1949 as follows:

Aircraft and auto	82 per cent
Medical supplies	73 per cent
Petroleum	58 per cent
Machinery and Tools	52 per cent
Electric power generation	51 per cent
Chemical and drugs	45 per cent
Iron and steel	45 per cent
Foods	38 per cent

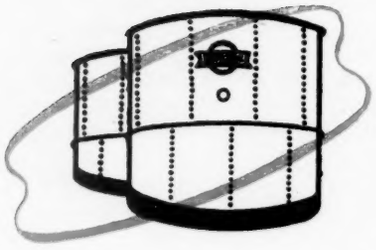
The establishment of *new* midwestern industry within this 10-year period accounts for an additional 12 per cent on the water resources of the area.

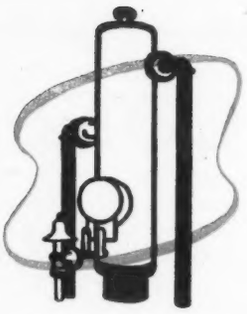
Although the total power generating facility of the country is divided into 4 major categories for statistical analysis, we must keep in mind that those plants dependent upon surface water or underground water constitute 96 per cent of the total installed capacity. Our present production of energy comes 50 per cent from coal, 32 per cent from oil, 14 per cent from natural gas and a round number 4 per cent in hydro developments. In the average steam turbine plant, 92 per cent of the water requirement is for condenser cooling. With the power industry being encouraged to increase its gross generating capacity at a rate of 5,000,000 kw per year for each of the next 10 years, a new water supply of 10,000,000 gal per minute may be required. Restrictions on the use of surface water, resulting from public welfare activity in the development of fish and game preserves, stream pollution abatement, and public health programs, dictates this increased water requirement be developed, in the majority, from underground sources. Yet available data indicates a current withdrawal exceeding natural replenishment in most industrial areas.

Our present average gross consumption of water is approaching 800 gal per day per capita. If only the power industry water requirement be

†Presented for The National Association of Power Engineers, Midwest Power Conference, Chicago, Illinois, April 4, 1951.

*Manager, equipment division, J. F. Pritchard & Company, Kansas City Missouri, and president, Cooling Tower Institute.





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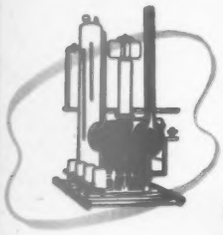

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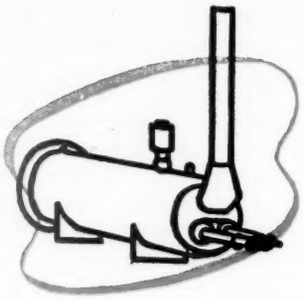

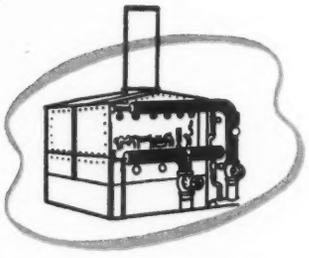

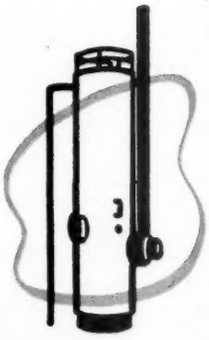

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considered or if only, by itself, the other industrial water load be considered, we might not be so actively concerned. When confronted with a constantly increasing population, however, with its domestic demand, we face, at the same time, the problem of developing an additional 100 gpm per capita supply within the area in the next 10 years. Although equating this total demand against our average 30 in. of rainfall per year over the continental land mass shows that we have developed facilities to utilize only 2 per cent of the total precipitation, we find the cost of water conserving equipment to be generally less than the cost of developing new sources of raw water. An extreme case at point is the new Key West, Florida, 5000 kw steam-turbine unit for which fresh water supply is pumped 150 miles through a 14-in. diameter pipe. A cooling tower is here definitely indicated.

On both coasts and across the northern third of the Mid-Continent area a gradual decrease in measured rainfall is recorded over the last 50 years. Wisconsin shows a decrease of 3.48 in. per year, New Jersey a decrease of 3.81 in. per year and Oregon a decrease of 3.81 in. per year. This is not yet established as a positive trend but is deserving of critical analysis before contemplated reservoir replenishment is accepted for power production within any one locality.

Statistics from the December 1950 publication of the Economic Policy Division of the National Association of Manufacturers covering basic industrial requirements on water use per unit of product are excerpted as follows:

Commodity	Unit	Average water requirement in U. S. gallons
Milk	1 gallon	5
Beer	1 gallon	15
Standard gasoline	1 barrel	10
Refined petroleum	1 barrel	420
Aviation gasoline	1 barrel	1,000
Synthetic gasoline	1 barrel	15,834
Corn on the cob	1 ton	1,000
Corn syrup	1 barrel	3,180
Soap	1 ton	4,493
Ice	1 ton	5,000
Steel	1 ton	65,000

By comparison the requirement of one gallon of circulating condenser cooling water per kilowatt of energy delivered to the lines of a steam turbine generator unit is a modest demand. As production requirements increase to meet the demand of augmented population, proportionate increase in water requirement is inevitable. Recognizing the tenet of public domain, with protective rights endowed upon our neighbor under our Constitution, it behooves the industrial user to minimize wasteful consumption of water.

The cooling tower industry is dedicated to improvement in the technology, design and performance of water conservation equipment. On this foundation, the formation of the Cooling Tower Institute was recently completed. The Institute hopes to share with industry responsibility of encouraging action on those steps necessary to avoid experiencing, as did the Union of South Africa, "an industrial slowdown because of an acute shortage of the most valuable mineral of all—water." We are not committed to the support of any particular style or type of cooling device. We are searching constantly for more efficient equipment suitable to general industrial cooling requirements and to our temperate climate. Our relatively high summer-time dry bulb temperatures virtually preclude the use of natural draft type hyperbolic shaped chimney towers extensively applied in power plant duty on the European continent. We do not have the steam wells recently developed in Italy where natural steam supplants the boiler in generating turbine steam which in turn goes through the standard expanding and condensing cycles. Even with such a natural steam source, cooling water for condensing is an essential requirement for the economical production of energy.

It is not enough to expend the waste disposal facilities of a community although excellent work in this separate field has been completed by the Industrial Wastes Conference at Purdue University, The Industrial Wastes Conference at Texas A. & M. College, the New England Industrial Wastes

ACCEPTANCE TEST PROCEDURE FOR MECHANICAL DRAFT TOWERS

Tests may be made by the Purchaser, under actual operating conditions, with the use of the following data and information

TABLE I
Design Data

DESIGN CONDITIONS
GPM_____°F.
Hot Water_____°F.
Cold Water_____°F.
Wet Bulb_____°F.

TABLE II
Tower Test Factor

COOLING RANGE	APPROACH TO WET BULB*				

TABLE III
Wet Bulb Factor

WET BULB	FACTOR

*Manufacturer shall be allowed a plus tolerance of 5% or ½° F, whichever is greater.

Performance may be calculated from data with above tables and following equations.

Design Performance = Design gpm × Tower Test Factor × Wet Bulb Factor.

D.P. = _____gpm × _____T.T. Factor × _____W.B. Factor = _____

Test Performance = Actual gpm × Tower Test Factor × Wet Bulb Factor.

T.P. = _____gpm × _____T.T. Factor × _____W.B. Factor = _____

When substitutions are made in the above equations, the "Performance Ratio" is

$$\text{Performance Ratio} = \frac{\text{Test Performance}}{\text{Design Performance}} = \frac{\text{T.P.}}{\text{D.P.}} = \_\_\_\_\_$$

If this ratio is more than One, the tower exceeds the design performance; if the ratio is less, the tower performance may be adjudged deficient.

Before starting a test, tower operating conditions should be adjusted to approximate the design conditions (Table I) insofar as practicable. During the test, the tower shall be clean and reasonably free of scale, mud, algae, and oil. The water distribution shall be equalized for all parts of the tower. Tests shall be made during the daylight hours, fair weather, and with tower in operation at test conditions for sufficient time prior to start, to assure stable conditions. The date and duration of test, as well as number and frequency of readings shall be agreed upon. Operating conditions shall be within the following limits:

1. Gpm water, ± 10% of contract.
2. Constant gpm during the test.
3. Average wind not over 7 mph.
4. Wet bulb, as limited in Table III, trend during test 2° F.
5. Range as limited in Table II.
6. Range variation during test, ± 5%.
7. Water solids, below 5000 ppm.
8. Fan hp, as specified in the contract.

Tests shall be made within twelve months following tower installation. Wet-bulb reading for each test to be the average of wet-bulb temperatures measured on opposite sides of tower along longitudinal axis of tower at air intake, and not more than 6 ft. above basin curb and within 10 ft. of air intakes, and at no less than three points on each side. All test instruments to be properly calibrated.

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WRITE FOR COMPLETE CATALOG

THE MERCOID CORPORATION
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Conference and those several groups sponsored by the American Chemical Society, the American Institute of Chemical Engineers and the American Petroleum Institute.

In the gradual development of the cooling tower and the air cooled heat exchanger, conservation of water has been the primary objective. Although in certain localities rivers, lakes, and ponds can supply small power plants with sufficient cooling water during the majority of the year, the forward looking engineer plans his plant around the use of spray ponds, evaporative coolers, atmospheric deck-type cooling towers, forced draft cooling towers or the more popular mechanical design known as the induced draft cooling tower. Each device utilizes the physical phenomona of latent heat in its function. For each pound of water evaporated within the equipment, approximately 1000 Btu of waste heat is ultimately dissipated into the atmosphere. In power plant duty, efficient cooling of the condenser water results from the circulation of 8 to 10 gals for each 1000 Btu heat dissipation. Typical water flow characteristics of three steam power plants currently under construction are:

Basic capacity (Corrected to P.F.=1) kilowatts	Steam condensing lb per hr	Inlet water temp	Condenser water circulation
25,000	175,500	84	25,000 gpm
20,000	150,150	80	20,550 gpm
5,000	49,000	82	6,950 gpm

For the plant operator to obtain preliminary structural, mechanical, and electrical data for a cooling tower to handle a certain condensing requirement, simple specification of heat load, desired water rate and temperatures, and ambient air wet bulb temperature will enable the cooling tower manufacturer to prepare basic design data. Consideration should be given to tower proportions of length, width, and height. Prevailing and next-prevailing wind direction may influence tower location with respect to plant and equipment position when the effect of downwind saturation is evaluated. Winter icing of the air intakes deserves detailed study in the same consideration with ice formation due to condensate precipitation to the ice of the structure. For the evaluation of cooling tower bids on a complete installation, tabulation of primary factors, at average values of cost, may be made as follows:

(1) Total average demand of fans and pumps	kilowatts
(2) Basin area	square feet
(3) Capacity cost, Item (1) x $1.75	$
(4) Basin cost, Item (2) x $2.50	$
(5) Total installed bid price	$
(6) Total capital investment, items (3) plus (4) plus (5)	$
(7) Annual fixed charges, item (6) x .075	$
(8) Energy charges, item (1) x 7000 x .004	$
(9) Total annual charge, items (7) plus (8)	$

Although the basic specifications for cooling towers should contemplate maximum turbine load and maximum heat rejection from the condenser, it is essential that partial load operation be considered in the selection of cell arrangement, fan diameters, fan drives, and water circulating pumps. The use of two-speed motors for fan drives permits appreciable reduction in power demand during off-peak periods. The use of steam turbine fan drives permits thermostatically controlled steam flow to the turbines with corresponding reduction in steam requirement during periods of low wet bulb temperature or off-peak demands. Recent developments in the hydraulic speed reducer field indicate definite possibilities for such applications with resultant economy. Partial load operation must be carefully studied for each particular condenser-turbine unit to make certain that the loss in vacuum resulting from the increase in entering water temperature or temperature rise within the condenser does not offset the power saved by reduction in cooling tower fan loading. Flow control on water circulating pumps deserves particular attention when we consider that the volume delivery of the centrifugal pump varies as the speed and the horsepower varies as the cube with the head varying as the square of the speed and a resultant power saving of only 45 per cent at

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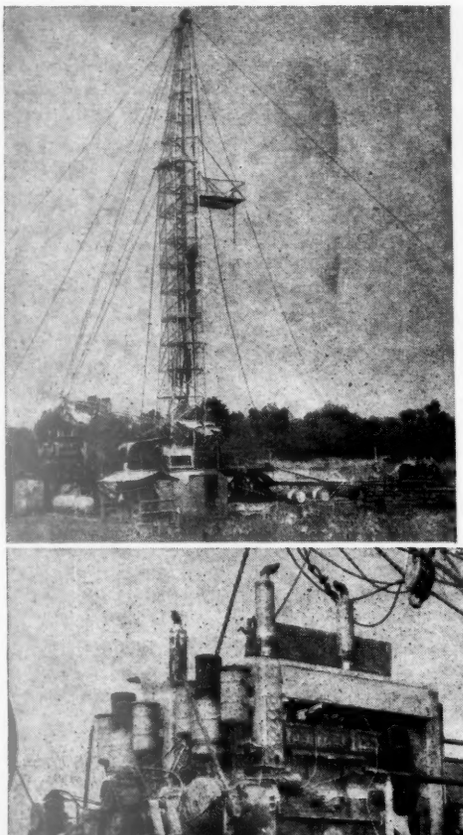
half speed operation is realized.

In the small diesel or gas engine driven generator plant, jacket water and lube oil cooling can be efficiently handled by "closed" systems utilizing atmospheric or shell and tube heat exchangers in conjunction with raw water circulation over spray ponds or spray towers if space is available and driftage is not objectionable. In the larger units, the waste heat may be dissipated efficiently by an induced draft cooling tower. In locations of high water cost or unavailability of dependable water supply, the recently developed air-cooled-heat-exchangers fulfill the requirement. These air-cooled units were gradually developed from the automobile radiator type of heat exchanger. Utilizing the mechanical equipment developed for cooling towers, the air-cooled devices are designed to force or induce a flow of ambient air over the extended tube surface developed by "fins" wrapped around or drawn out of a heavy wall tube through which the treated circulating water is pumped. Efficient designs of finned tubing often deliver 2.5 times the capacity of plain tube surface per square foot of effective external area. Without the advantage of latent heat phenomena utilized in cooling tower function, the air cooled exchangers, dependent upon dry bulb temperatures of the ambient air, compare favorably in total annual charges to the cooling tower installations on the internal combustion engine driven generators. With 100 F dry bulb air passing through the finned tubing 140 F water temperature can be achieved efficiently. Obviously the economy of the air-cooled designs is lost when the temperature requirements fall close to or below the ambient dry bulb temperature.

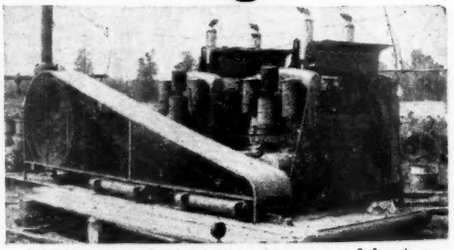
With 8 of our 48 states presently controlling the use of surface and underground waters within the state by legislative regulation and with 131 major cities preparing to answer the problem with local regulation governing the use and waste of water, thorough investigation of water conservation procedures will soon be standard engineering procedure in the consideration of power plant operation, expansion, annual operating costs and plans for ultimate plant requirement. The pattern for state regulation is already definied by the Ohio State Water Resources Board and the Minnesota Division of Water Resources and Engineering. Statistical data on the subject is outlined in the Hoover Report of 1949 pamphlet entitled "Department of the Interior" and in the Task Force reports on Water Resources Projects (Appendix K) and Public Works (Appendix Q). Basic geological data is available from the U. S. Department of the Interior in "Publications of the Geological Survey" dated May 1948. Pioneers in the approach to the water problem have published their findings in the 19th report of the Texas Board of Water Engineers for the State of Texas. Collateral data on a typical local situation is available in Bulletin No. 5101 on the Water Supply of the Houston Gulf Coast Region as published by the Texas Board of Engineers at Austin, Texas, prepared cooperatively with the Geological Survey of the U. S. Department of the Interior in January, 1951. The President's water resources policy commission has published a summary of recommendations for a "Water Policy For the American People" in which is stated the broad framework of a principal proposing a reformulation of water resources as a Federal function. It is to be hoped that the foresightedness of the power industry in its judicious use of efficient water conservation devices may so minimize the requirement of Federal action that major emphasis may be placed upon the preservation of our greatest natural resource rather than upon the regulation of its use in the production of energy. * * *



Beene-Hurley Use Low Cost Power on Frank's Rig!

Drillers Beene and Hurley at Bossier City, La., use Frank's portable rig with four Minneapolis-Moline 1210-12A units for power. They are drilling low-cost wells to depths of 6500 feet. The 1210-12A, 12 cylinder unit engines are factory equipped to operate on LP gas or natural gas—the low priced fuels in this area.

Beene and Hurley have mounted two of these units on the drilling table to furnish power to the draw works. These engines are equipped with front power take-off drives and supply 400 hp with LP gas. The other 1210-12A units are remotely located on the mud pump. The complete engineering and installation was done by Beene and Hurley at Shreveport.



Mud pump installation is powered by two MM 1210-12A's.

Two MM 1210-12 on the drilling table operate on low-cost, higher octane LP gas.

This arrangement combines flexibility of layout with important time saving for setting up the rig. Precision tooling and high production methods account for the extremely low selling price of MM heavy-duty oil field power units. Standardization of parts permits interchangeability which assures easier, lower-cost maintenance.

Sales and service of MM oil field engines are handled by the Shrimpton Manufacturing and Supply Co., with branches at Los Angeles, California; Oklahoma City, Oklahoma; and Kilgore, Texas.

The SPIRIT of SPINDLETOP†

B. BREWSTER JENNINGS*

I WELCOME any occasion that requires my presence in Texas. Particularly in these days, when bigness is so often confused with badness, I appreciate even a few hours' association with you who are not ashamed of bigness either in your state or in your way of doing things. Troubles that have loomed large because I have been close to them soon appear small in Texas. Sometimes I wonder if it wouldn't help to move the White House down here two or three times a year.

When an event does look big even against the backdrop of Texas, and from a distance of half a century, it is big indeed. Such an event was the discovery of Spindletop. Why was this particular oil field so significant as to warrant this wonderful celebration of the 50th anniversary of its discovery by Captain Anthony Francis Lucas?

To see Spindletop in its proper light, we need to view it against a background of the oil industry as it was at the turn of the century. Until about 1900 oil products were used only for lighting and lubricants. Except for some experimenting by a few visionaries, who thought the internal combustion engine could be made to work, no oil was used as a source of energy. In 1900 the entire year's production in the United States was only 64,000,000 bbl, about ten days' production at current rates. Russia's production that year exceeded ours by 11,000,000 bbl.

Prior to Spindletop, the area within which oil was produced in America was primarily western Pennsylvania, southern New York, eastern Ohio, and northern West Virginia. This limited area was referred to as *The Oil Regions*. The name is still in use despite its obvious inappropriateness.

Spindletop Encouraged Others

Against that background, the discovery of Spindletop assumes great significance on several counts. If oil in vast quantity could be found 1200 miles away from *The Oil Regions*, certainly it might be found in many other places as well. Its discovery waited only on the drilling of enough wildcat wells. Unquestionably, the great Spindletop gusher gave a tremendous spur to the American producer of oil and in fact encouraged adventurers to try their luck wherever they could in other parts of the world as well.

Certainly if there had been no prospect of finding oil in much larger volume than had been found up until 1900, the outlook for the horseless carriage would have been pretty dim.

Spindletop thus was the beginning of the modern oil industry, an industry that is primarily a supplier of energy though, of course, it produces many other valuable things. Spindletop sparked an all but incredible expansion in the search for oil in this country. By 1909, production in the United States was more than three times the pre-Spindletop rate. Ten years later, our production had doubled again, and exceeded a million barrels a day. Now it is almost 6,000,000.

One Auto for Every Four Persons

In the last 50 years we have become a nation on wheels, with a passenger car for every 4 people. About a fourth of our homes are oil-heated. Practically all of our ships, whether deep-sea or inland waterway, now are oil-fueled. Even railroads are now using oil for more than half their power needs. Farming, of course, has been revolutionized by the substitution of tractors that consume nothing but oil for animals that must be fed part of the crops they help to raise.

It would be a mistake, however, to think that these vast changes have come about and will continue to take place willy-nilly. If that were so, we might have expected the oil industry to develop at about the same rate in *all* countries where it had an equal start with our own. On that basis, Russia should be the greatest oil-producing nation in the world today. Fortunately for us, and for the hopes of free men everywhere, we had something, besides oil, that Russia lacked.

As Wallace Pratt points out in the Spindletop issue of "Texas Parade," that something is freedom of enterprise. Pratt reminds us that the United States includes only a very small part of that portion of the earth's crust that we believe to contain oil, and that the lands controlled by Soviet Russia are far more richly endowed with natural resources in oil than our country ever was. To the question why the United States' production has so far outstripped Russia's despite Russia's head-start and greater potential, Pratt answers, "It is the superior natural resourcefulness of this country, rather than its superior natural resources, that has given it an abundance of oil." Per unit area, we have drilled in the United States more than a hundred times as many exploratory wells as the rest of the world.

A Triumph for Free Enterprise

Spindletop itself was a triumph of freedom of enterprise. Experts from both Standard Oil and the U. S. Government independently reported there were no indications or precedents for expecting to find oil there. Only under a system that makes it possible for free men to bet their money against the powers that be and the authorities that are could the Spindletop discovery have been made when it was.

There are trends in our economy, and more particularly in the thinking of some of our political leaders, which cause concern to those who believe, as I do, that freedom of enterprise is vitally necessary to our continued well-being. To me, freedom of enterprise means that the economy as a whole, and more particularly any given industry within the economy, must have freedom to adjust its operations to the constantly changing pressures within that economy. It does not mean any such thing as freedom to monopolize, to restrict production, to withhold new processes, to force down wages, or any of the other socially undesirable things of which free enterprisers are often accused. We have developed in the United States a pretty complete body of laws to prevent such abuses of freedom.

†Presented before Spindletop 50th Anniversary, Beaumont, Texas, January 10, 1951.

*President, Socony-Vacuum, Oil Company, Inc.

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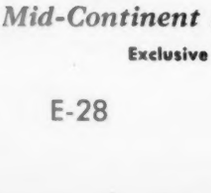

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Our present danger, it seems to me, is the enactment of laws that would prevent the proper and essential use of freedom.

Perhaps I can make clearer what I mean by a simple illustration. As motorists, we do not regard it as any infringement on our freedom that we have laws telling us how fast we may drive, requiring us to keep to the right, and barring us from driving at all when we have had too much to drink. In big cities, we even accept regulations as to which direction we may travel on certain one-way streets. But there is all the difference in the world between laws telling us how we may travel and laws telling us where we must travel.

No reasonable citizen can oppose legislation or regulation prohibiting wasteful flaring of gas or requiring the pressure in oil-producing reservoirs to be maintained. Texas has been a leader in that type of sound exercise of the government's police power, in effect limiting the freedom of individuals to harm each other. Where we must be careful, if we hope to preserve the unique values of freedom of enterprise, is in permitting government to go beyond the exercise of such police powers and manipulate the economy itself.

Industry Meets Sudden Demands for Oil

In the 50 years since Spindletop came in, we have had to transform the oil business from one which was primarily a maker and seller of kerosine for lighting to one able to meet an almost overwhelming demand for power fuels, chiefly gasoline, of course. Within the last 10 years particularly, we have had to make extensive changes in our refining to meet a rapid and rather sudden increase in demand for home heating oils and diesel fuels. The fact that these complex changes have been worked out smoothly, efficiently and economically argues that freedom of enterprise has worked pretty well. I doubt that these changes could have been effected if a central agency of government had been solely responsible, had been required to foresee the changing demands and then direct and order the multiplicity of actions necessary to meet the new situation.

Because freedom of enterprise is so vital to the future of our industry, we must be ever-watchful to detect in the sometimes plausible arguments of proponents of control the proposals that are totally incompatible with our essential freedom. I should like to mention just a few of the recent moves which, if successful, would restrict the

oil industry's freedom to react to economic pressures. That is just another way of saying restrict the oil industry's ability to adjust itself to your changing wants and needs. Some of these control efforts are initially applicable to natural gas, but because of the close relationship of gas and oil, they must ultimately impinge equally on oil.

What Criterion Would the Experts Use?

For example, there is great concern in some government circles about the price at which natural gas is sold, not as one might expect, the price paid by the consumer, but the price at the well as it issues from the ground and before it enters into commerce. Some people want to legislate a minimum price. The argument runs that gas is intrinsically worth at least X cents per thousand cubic feet, and that to sell it for less is wasteful. One may ask by what criterion is the expert who is charged with this responsibility going to figure the precise price at which gas should be used and below which its consumption is wasteful.

One may wonder, all things considered, whether Americans would be better off today if legislation had prevented the sale of Spindletop oil until it reached a price that some governmental authority decided was fair. Or did the sale of that oil at prices then obtainable stimulate the development of the automobile and other industries in ways that otherwise would not have been possible?

Would we be better off if by such minimum price legislation we had retained in the ground half of the oil we have removed since 1900 but as a result found ourselves with only half the automotive and oil industry capacity that today constitutes so large an element in our defense potential?

Setting Minimum Prices for Gas

This question of setting minimum prices for gas has been argued all the way to the United States Supreme Court and by a decision handed down on December 11, 1950, it is constitutional for the states to enact minimum prices for natural gas if they choose to do so. I am not concerned with the constitutionality of such legislation, but I do question the wisdom of such a course.

Besides the minimum price advocates, there is an even more vociferous group who feel that a maximum price for gas at the wells should be set by government. Their argument is that gas is used by millions of consumers, and these consumers must be protected. It sounds plausible enough,

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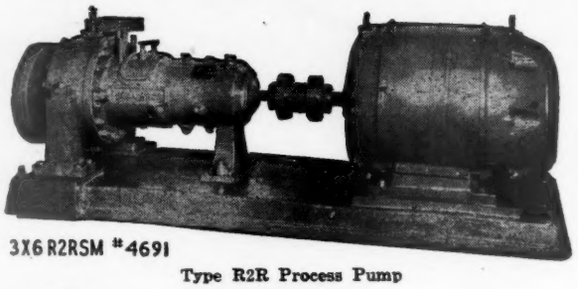
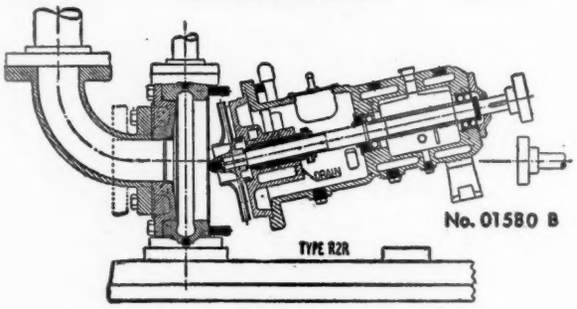


Type R2R Process Pump



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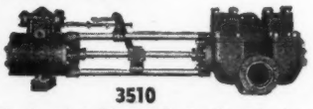

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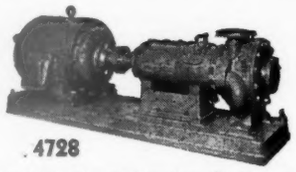
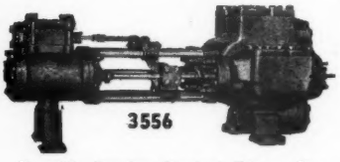


Double Pedestal Bearing Centrifugal Pump



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but why do these particular consumers require protection over and above that afforded us all by the law of supply and demand? If we really believe in the price system on which our freedom of enterprise is based, nothing justifies price-fixing except a government-authorized monopoly such as a public utility. So long as an industry is competitive, as the production of oil and gas certainly is, the long range interests of the consumer will never be served by fixing prices below the levels they would reach in a free market.

The issue of maximum gas prices was fought with extraordinary heat and acrimony in the congressional session of last year. Senator Robert Kerr, of Oklahoma, introduced a bill that would have prevented this type of regulation. After passing both houses, the bill was vetoed by the President.

Natural gas is produced from thousands of wells, either by itself or in conjunction with oil. The well operators are trying to sell this gas as conveniently as possible and at the best price obtainable. Buyers of the gas, actual and potential, are the industrial plants near the fields, the local gas companies, and most important, the natural gas transmission line companies that move the gas from the fields to the large urban market areas. The pipe line companies are utilities that are properly subject to regulation as to their charges for the service of transporting and distributing the gas. The gas, however, is a raw material, entering into industrial or utility use and is not of itself a utility until it has entered the utility system.

Price Levels Set in Marketplace

There is in my view no more justification for setting a top price on natural gas at the well than for setting a top price for oil at the well, coal at the mine, steel at the mill, or for any other commodity normally free to enter commerce in response to and at the price level set by economic laws operating in the marketplace.

Price-fixing for a competitive industry in peace-time is as much of a crime against our system of freedom of enterprise as the old Chinese custom of binding their girls' feet, or an African tribe's custom of binding their infants' heads. A crippled, misshapen economy can be the only possible result.

There are those who are uneasy because there are big companies in a particular industry. We hear this often about our industry, and so I want to talk briefly about "Bigness in Oil." We all know of the suit against

the Standard Oil trust, which resulted in its dissolution in 1911. Looking back, one can readily understand the popular fear of a private enterprise doing some 85 per cent of the business in an essential industry, yet it is significant that many oil companies that are hale and hearty now began their careers in oil long before 1911 and prospered despite the supposedly insuperable competition of Standard. Tidewater (now Tidewater Associated) was founded in 1888, Union Oil in 1890, Sun Oil in 1901, the Texas Company in 1902, and Gulf Oil in 1907. These companies and many others actually became important factors in the industry with the discovery of Spindletop. The record shows that by and large there is always room for a new company, provided the newcomer is as competent and efficient as those already in the field.

Competition Makes for Efficiency

Imagine a new industry in which no really competent people are engaged. The standards of performance in such an industry would be low, efficiency poor, and costs high. Such an industry could not supply goods and services to the public as effectively as it should.

Now, suppose a new outfit with top-flight management enters the field. The new company finds that it can make a lot of money at the prices charged by its inefficient competitors and can make still more by lowering its prices and increasing its volume. Pretty soon the inefficient firms find that they either have to improve their methods or quit. In a relatively short time, the entire industry is transformed from a sloppy, high cost one to an efficient low cost operation. The resulting gain to the public through getting its goods cheaper and better far outweighs the loss suffered by the inefficient firms which had to go out of business.

The existence of a really efficient, aggressive company in every industry is the best and perhaps the only guarantee the public can have that it is being well served by that industry. The existence of the A & P is a guarantee that we are getting our food at the right price and of the right quality. We don't have to buy it from the A & P—any food store has to be good or it won't be able to compete with A & P. General Motors, or Ford or Chrysler give us the same assurance regarding our automobiles.

I believe that back in the 1880's and 90's the existence of Standard Oil resulted in there being available better and cheaper oil than there otherwise would have been. During those years, Standard Oil set standards for the oil industry that were high. The other companies that began and grew in that exacting industry adopted those standards and, of course, tried to improve on them.

Oil Industry Is Not Found Wanting

Today it seems fair to say that there is no industry that over the years has done a better job for the public than has oil. In terms of wages and working conditions, prices, quality, progress, by whatever yardstick you use, the oil industry is not found wanting. Those are strong statements but I can back them up.

In a period of generally-rising prices, aggravated by the inflation associated with World War II, we find gasoline (before taxes) selling at approximately the same price at which it sold 25 years ago. Not only that, but today's gasoline is so much better than the gasoline of 25 years ago that two gallons of the product that goes into your tank now will do as much work, measured by any standard, as three gallons did back in 1925. Put another way, the oil industry is giving you, with each gallon of gasoline today, 50 per cent more useful energy than it did in 1925, and is doing so at the same price, in dollars, that you paid in 1925, notwithstanding the sharp reduction in the purchasing power of those dollars in the last two and a half decades. And we thought the oil industry was good in 1925!

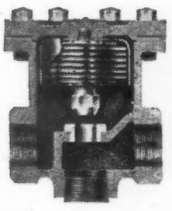
Obviously much of what I have said about freedom of enterprise is subject to the overriding necessities of total war. The marshaling of national effort required by modern warfare necessitates a pretty thorough national control, and in these days when wars are begun first and declared afterward such national control has to be imposed before the war is made official. Let us never forget, however, that all our government can do is to deflect our nation's strength into military channels. It did not and cannot create that strength.

Oil Industry's Strength Aids Nation

Throughout our history, the oil industry in its competitive struggle to please its customers, has built up its strength to protect the nation. In the five years since V-J Day, we have drilled 175,000 wells, increased our crude oil reserves in the ground by 6,000,000 bbl, and raised our potential maximum rate of efficient production by 1,600,000 bbl a day. Our refineries have enlarged their capacity

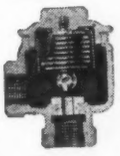
Nicholson Steam Traps

STOP BACK-UP of CONDENSATE



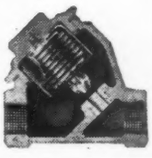
Type B

Operate on Lowest Temperature Differential

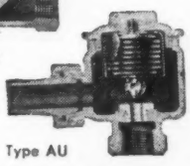


Type A

Repeated comparative tests by large trap users show that Nicholson steam traps operate on lowest temperature differential, and thus prevent waterlogging. Plant records show that, by keeping equipment full of live steam, they have increased production of cooking kettles, for example, as much as 30%. Widely specified for preventing damage to thin gauges. Eliminate "cold blow" in unit heaters. 5 types for every industrial application. Size ¼" to 2"; press. to 225 lbs. BULLETIN 450.



Type AHV



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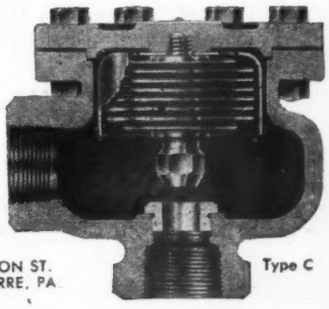

Type C

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by 1,500,000 bbl daily, and our transportation system has been importantly expanded.

Abroad, too, American oil companies have increased capacity in all departments. U. S. companies in South America are currently producing 450,000 bbl a day more than in 1945, and their refining capacity is up by some 200,000 bbl a day. In the Middle East, American interests currently are producing about 8 times what they were at the close of the war.

Not only is our industry in good shape as to physical plant but in organization as well. Oil men were among the first to give thought to possible future emergencies. Almost three years ago, a committee of the National Petroleum Council made recommendations as to the best type of organization for a possible future conflict. When it became evident that to supply the military demand for petroleum products for the Korean war, government authority and cooperation were needed, Secretary of Interior Chapman was able to move promptly and effectively. In the Petroleum Administration for Defense, there is in my judgment an excellent government organization, well designed to supplement the oil industry's own effort in the many ways where government action is essential. I think we can be confident that when the chips are down, we of the oil industry will do our part.

Allies Control 9/10ths Oil

If war comes, it is going to be a conflict between two adversaries singularly different in general characteristics. On one side will be a vast aggregation of people, relatively ill-equipped, and lacking in industrial potential. That is the kind of adversary we and our allies will face. By comparison, our team will be numerically smaller, but we shall have by far the greater potential measured by any criteria dealing with industrial output.

Our great industrial potential is of course based on unprecedented utilization of energy. Of all the available sources of energy, by far the best for war is oil. In fact oil is the *only* fuel that modern armies, navies, and air forces can use. Oil gives our forces virtually unlimited mobility, as compared with the relative immobility of non-motorized forces. In a conflict between large masses of manpower on one side and smaller, better equipped units on the other, mobility can and will be a determining advantage. The United States and its probable allies control about nine-tenths of the oil of the world. Though an enemy might deny us the use of some fields we now operate, we would still be overwhelmingly superior in this vital resource.

However harsh the trials of the oncoming years, we in the oil industry face them with limitless confidence in the capacity of the free human spirit to rise above them. Should the forthcoming year bring full scale world war despite our efforts and prayers for peace, there is no doubt in my mind of our ultimate triumph. Our greatest peril, it seems to me, is not that we may have to fight, but that we may be forced into such a prolonged state of readiness to fight that we abandon too far and too long that freedom of enterprise—the Spirit of Spindletop—without which we never could have achieved our present superior ability to fight.

America has many Spindletops, not only in oil but in science and industry—in our colleges and universities. You will hear about some of the others tonight. As Americans we are justly proud of them. They are tangible evidences of our country's greatness—the fruits of our strength, but not the primary source of it. For that we turn to the greatest treasure of them all—the Spirit of Spindletop. It is to that spirit, rather than to an oil field, we pay homage here tonight.

* * *

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MIDDLE EAST†

Oil Developments†

CHARLES L. HARDING*

UNINFORMED people sometimes seem to think the oil industry has been lifted to its present eminence by an insatiable demand for its products regardless of price. Every oil man knows how far that is from the truth but probably no segment of the oil industry has achieved success over greater obstacles than yours. I have the utmost respect for your organization and what it has accomplished.

From the standpoint of total recovery derived from secondary-recovery operations, such as repressuring by air and gas injections, and artificial water floods, Pennsylvania is the most important state in the country. To your association is due much of the credit for the aggressive and enterprising leadership that brought these mutual benefits to the oil industry and the consuming public.

On all sides there is even greater need for cooperative effort in the Middle East than that which led to the formation of the Pennsylvania Grade Crude Oil Association.

Notably in recent months, there has been a growing public awareness of the Middle East and its importance to the United States and to the freedom-loving countries outside the Russian orbit. Fortunately for the Western World, the oil industry of the United States and Great Britain has been alert to the potentialities of the Middle East for nearly half a century.

The value of this area is due not only to the immensity of the petroleum resources known to exist there but also to the strategic location of the Middle East in any conflict between western nations and Russia. It seems to me vital to our future well-being that there should be general appreciation in this country of what is at stake while there is yet time to discuss that stake in terms of what may be rather than what might have been. Within the past several weeks a great deal has been written and said about the action taken by Iran to nationalize the oil industry. However confusing this may have been as to the issues involved, it has helped to educate our people further as to the importance of this area to us all — the United States as well as Great Britain and Europe. The education may be a little like a boy getting a spanking. He is told that it is good for him, but he wishes there were a less painful way to learn. But the education is essential if public opinion is to exert its proper influence on our international policy.

U. S. Produces More Than Half of the Oil in the World

Currently the United States is producing more than 6,000,000 bbl of oil every day from wells within our own national boundaries. That is more than half of the oil being produced in the entire world. With such an overwhelming leadership in oil production from our own domestic reserves, why should we be interested in, let alone worry about, as to the oil situation anywhere else? Would it not mean just that much more prosperity for the American oil industry if some of the foreign production was shut down for awhile?

To answer these questions for ourselves, as Americans, let us start by looking at the flow of oil in world trade.

Our own vast production has little effect in world trade because we use it all at home, and a great deal more besides.

Nearly half of the three and one-third million barrels of oil that moved in international trade every day last year came from the Middle East and nearly 60 per cent of those Middle East exports of oil went to Europe. More than three-fourths of Europe's oil needs were supplied by the Middle East.

We have here in the United States little margin of excess producibility on which to draw if we should be called on suddenly to supply Western Europe with the oil now coming from the Middle East. All this points up the danger that if we were to lose the oil of the Middle East now, we might not have enough oil to supply both our own rapidly expanding needs and even the minimum requirements of our friends in Western Europe. Loss of Middle East oil, in other words, might confront us with the unpleasant choice of rationing our own people or of turning our backs on Europe after we have just spent billions of dollars to promote economic recovery there.

To see the importance of the Middle East to our more distant future, we need to realize first that the United States which has less than a third of the world's crude underground oil reserves is using almost two-thirds of all oil produced in the world. We need to realize further that even if we could call on Canada and all of the countries to the south of us, we should still have in the entire Western Hemisphere less than half of the world's known reserves from which we are producing nearly three-fourths of the world's current oil supply, while the Middle East with 45 per cent of the world's reserves produced only 16.5 per cent of the world total last year. Whether we consider the United States alone, or take the entire Western Hemisphere as a unit, our part of the world is drawing on its known reserves of oil at a much faster rate than the rest of the world.

And if the present trend of rising oil consumption continues, we shall be using in the United States alone, less than two decades from now, more oil than the entire world including the United States is now producing.

The total known reserves of the world outside Russia approximate 85½ billion barrels. That huge total is divided roughly equally between the Eastern and Western Hemispheres

†Presented before the Pennsylvania Grade Crude Oil Association, Pittsburgh, Pennsylvania, June 14, 1951.

*Director in charge of Middle East Affairs, Socony-Vacuum Oil Company, Inc.

— just under 43 billion barrels in each. But of the total oil resources in the Eastern Hemisphere, nearly 41 billion are located in the Middle East.

In the Western Hemisphere the United States has proved reserves of about 29½ billion barrels.

Potential for Adding New Proved Reserves

As oil men, you know that proved crude reserves depend in part on the number of wells drilled. Just to give you a very rough idea of the comparative activity in the two areas, the total number of wells drilled to date in the Middle East is fewer than 2000, compared with 1,342,000 in the United States. You, of course, will draw your own conclusions, but to me it seems self-evident that the potential for adding new proved reserves in the Middle East is greater than in this country. Dr. C. M. Lees of the Anglo-Iranian Oil Company has just reported to the World Petroleum Congress that ultimate Middle East reserves are estimated at 200 billion barrels, twice the estimated potential reserves (ultimate production) in the United States.

Please do not misunderstand me. I am not one of those people who believe we have exhausted our finding efforts in the United States, or that we are running out of oil. It is a question of comparative values and of long range outlook.

The vast and all-important oil resources of the Middle East have been developed largely by British and American capital and organizations. I am not overlooking the interests held by the Dutch and French in this picture but our concern today is primarily with the general situation and not with the details of ownership. These British and American organizations also have promoted the sale of this Middle Eastern oil throughout the industrialized sections of the world. Because oil is an efficient and inexpensive source of energy, demand for it has steadily and rapidly increased to the point where the standard of living in many countries is largely dependent on the continued flow of low priced petroleum products.

The oil companies in my opinion have performed a great public service in making possible this use of petroleum. Political stability in a country increases with the number of people owning and enjoying the material things of life that provide comfort and make for contentment. While a large part of the population of a country is destitute there can be only unrest, which ultimately expresses itself destructively. Such a condition cannot be cured by taking from the wealthy few for the benefit of the many if there is not enough to go around. Everywhere it has been tried, the result has been merely to make everyone destitute.

Average Consumption for Each Person in U.S. 592 Gal

The only remedy I know of is to produce more wealth, to create sufficient goods to give a greater proportion of the population the fundamentals of more comfortable living. This can be done only by substituting mechanical energy for human energy. There is a cause and effect relationship between the fact that we in the United States have the highest standard of living in the world and are far and away the largest per capita consumers of oil. In 1949 our oil consumption averaged 592 gal for each person in the United States compared with a per capita consumption of 101 gal in Britain and 63 gal in France. Development of the use of oil by our petroleum companies is bringing about greater productivity wherever that oil is consumed.

In a very real sense the great growth in the use of oil around the world tends to bind all peoples together, making nations more interdependent. The European economy is inextricably woven into that of the Middle East. The Middle East is equally dependent on the industrialized nations to transform its crude oil, which is of little value in its natural state, into products that will increase standards of living wherever they are used. Badly as the industrialized nations of Europe need oil from the Middle East, they need it no worse than the Middle East needs European oil markets.

Since the last war it has been generally accepted that no nation can live alone in this world. Today the earth is more or less divided into two camps. We must have friends to survive. Our friends must have strength. A strong ally is a life preserver. A weak ally can be a millstone. We and our allies must be stronger than the enemy, if possible enough stronger to dissuade him even from trying to overcome us by force. That, I believe, is the object of the Marshall Plan and other similar undertakings. It means we must build into those nations which are our friends greater capacity to produce. It means oil must continue to flow to those countries to provide them with an efficient low-cost source of energy to produce both armaments and civilian goods.

Oil from Western Hemisphere Is Not Sufficient

Where is this oil to come from? Our production in the Western Hemisphere is not now sufficient to supply our own needs and have enough left over for the friendly countries in the Eastern Hempishere. We may have to depend on the Middle East for an increasingly large proportion of these supplies. Failure to supply Europe's needs for petroleum would seriously handicap the Marshall Plan, the North Atlantic Treaty Alliance and our broad objective to build political and industrial stability in the world. It could mean the failure of the whole program. Should the oil of the Middle East no longer be available we would not abandon our plans to forsake our friends. We would attempt to replace that oil as much as possible from the Western Hemisphere. To do so might require rationing in the United States, rationing perhaps more severe than ever before.

This line of thought necessarily leads us into the field of international politics. Unless we are careful when we roam into that area we may find ourselves in "No Man's Land" between the proponents and opponents of the Administration's foreign policy. Yet to attempt to discuss the world oil situation, or the circumstances in the Middle East, without reference to Russia, would be like nothing I can think of except that familiar jingle:

"Mother, may I go out to swim?
Yes, my darling daughter,
Hang your clothes on a hickory limb
But don't go near the water."

You may be interested in our best guess as to the oil resources now available to Russia. Our calculations are that including the satellite countries the Communist nations have about 5½ billion barrels of proved reserves from which their daily production is around 850,000 bbl.

Oil production controlled by the free nations thus is something better than 10 times that which is controlled by the Communists.

It would not be surprising if the Soviet tried hard to change that ratio in Russia's favor. As in an election, where each vote switched counts double by reducing the opponent's total at the same time it adds to your own, Russia would gain doubly by getting part of Middle Eastern oil. Its loss would weaken our side and its gain would strengthen Communism. The chief value of the oil now is in bolstering the economy of Western Europe and making it unnecessary to send oil from the Western Hemisphere to Europe. But the oil of the Middle East could be used just as advantageously by Russia for the development of Communist China and other parts of the Far East friendly to the Soviet. Our country is buying billions of dollars of insurance against the possibility of further aggression by Russia. If Russia is planning war,

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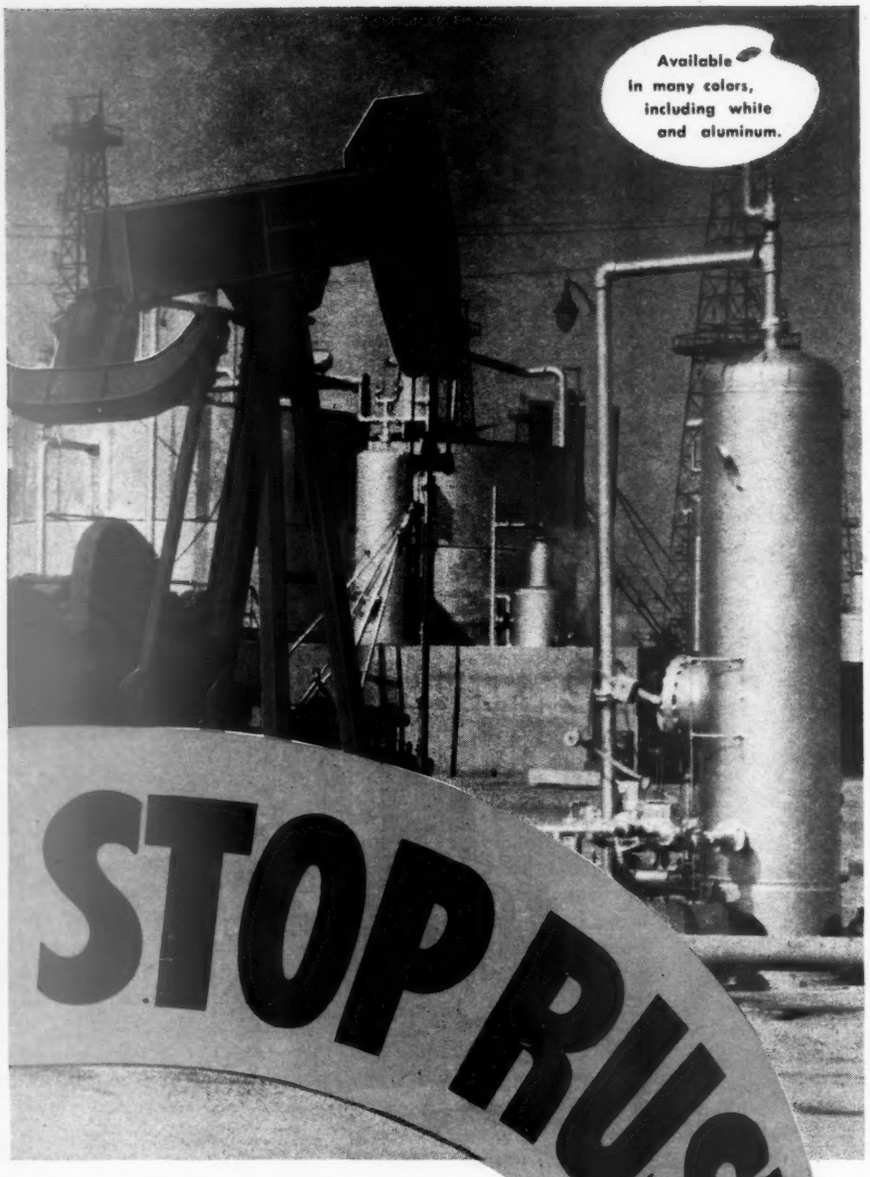

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any marked improvement in her supply of oil would remove one more deterrent, just as did her reputed success in producing the atomic bomb.

Need I say more about the importance of Middle East oil to our economy, to our National Defense, in fact to our potential ability of Western nations to survive? If a numerically superior enemy could deny us the oil of the Middle East, probably the richest source of energy in the world today, and then could integrate that oil into his own economy, it might tip the scales against us.

Implications Affect Welfare of All Nations

Against this background comes the move on the part of Iran to nationalize its oil. It is a delicate subject and even if I were up to date on developments in that troubled area as of last midnight, my report on it might be obsolete by now. There are, however, certain implications growing out of the attempted abrogation of contract — implications which, to my mind, reach out beyond this dispute and affect the welfare of all nations and perhaps the future of international conduct.

In many producing countries it is believed that the mere presence of crude petroleum within that country is of itself an item of immediate usability and great value that more or less can be dealt with as a gold coin. You of course know the fallacy of such a view. Crude petroleum has little value in the middle of a desert or up in the mountains. It is only after it has gone through all the steps that transmute it from crude oil to energy, and lubricants and other media for the creation of new wealth that it has real value. It is the job of the petroleum industry to convert this article from something almost useless in its natural state to material of value in world commerce. It cannot be repeated too often that the producing countries and the consuming nations are dependent on each other. This is a principle that I believe any country fortunate enough to have oil resources should never forget.

Likewise significant at this time is the fact that the oil reserves of the Middle East are not situated entirely within the boundaries of a single nation. They are in fact rather evenly distributed over 4 or 5 different areas. This means that no particular source of supply is now indispensable or will be as far ahead as we can see.

Have No Financial Interests in Iranian Oil Fields

The contractual situation with respect to the arrangements between Anglo-Iranian Oil Company and Iran

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merits special consideration. The fact that Iran has the only major oil fields in the world in which no American companies have any financial interest may be purely coincidental. The fact that the move in Iran took the form of nationalizing a company more than half-owned by the British Government which has recently been doing a good deal of nationalizing of industries in its own country likewise may have been purely chance. Taken together, however, those coincidences have created a more difficult situation than might otherwise have confronted us. The principles involved are none the less pertinent to all of us.

In 1901 Persia, which as you know is now called Iran, made a concession agreement with the Anglo-Iranian Oil Company to develop Persia's crude oil reserves. Late in 1932 the Persian Government announced the cancellation of the oil concession under which the company then was operating. The British Government acted vigorously, taking the matter to Geneva in order that it might be dealt with by the Council of the League of Nations itself. There was a hearing by the members of the Council sitting around the table in the League of Nations Building.

The then foreign secretary presented the British case with documents and argument. The Persian case was presented by a distinguished French advocate, whom Persia briefed for the purpose. The late Dr. Benes of Czechoslovakia acted as judge. The dispute was amicably settled by the Agreement of 1933, which attached new terms to a concession that was to last for 60 years, till 1993. That new agreement was signed on April 29, 1933, for the Imperial Government of Persia by His Excellency Mr. Taqizadeh, the then Minister of Finance, following its ratification by the MAJLIS or Parliament and the royal assent of the Shah. There can be no question but that it was freely entered into by the Imperial Government of Persia. By it Persia obtained additional advantages of great value. Not only was the rate of royalty increased for the future, but the increased rate was paid retroactively for the years 1931 and 1932, instead of the lower rate previously stipulated. Further, Persia received a lump sum of 1,000,000 lb sterling.

Article 21 of the new agreement provided:

"This concession shall not be annulled by the Government and the terms therein contained shall not be altered either by general or special legislation in the future, or by administrative measures or any other acts whatever of the executive authorities."

The issue involving the Anglo-Iranian Oil Company in Iran is not primarily that of nationalization. In point of fact the Iranian Government has always owned the oil reserves. The concession it made with Anglo-Iranian is a contract with the oil company for the development of the country's oil. Thus, as I see it, the present issue is essentially one of abrogation of contract.

Faith Is Prerequisite to Every Business Deal

Regardless of the legalistic concepts, we must all agree that if sovereign governments are going to abrogate contracts unilaterally whenever it suits their purpose, there will be no basis for international commercial relationships. You men know from your own experience in Bradford, Oil City, Warren and elsewhere that faith in someone's spoken or written contract is a prerequisite to every business deal. International business is no different. The oil industry of Iran was developed by men and money from another country acting on faith in a contract.

As the new industry developed it became vital not only to the economy of Iran but to other nations, which came to rely on it as a source of supply. The question is not merely one affecting Iran alone. Industries and activities vitally affecting the lives and welfare of other people have been predicated on this supply of oil.

In the world today we are endeavoring to adopt a higher order of conduct among nations. We are searching for a substitute for armed force that has so often governed in the past. We are contending that the law of the jungle should no longer apply to problems arising among nations any more than it should apply to the problems arising among private persons. This is a higher order of society. It must live by a code of conduct under which rights of nations and individuals engaging in foreign operations are observed. The principles of respect for property rights and the sanctity of contracts are basic in such a code. If the civilized world accepts without protest violation of these principles, the international investment and trade required for the economic well-being of the peoples of the world will be inhibited, and the objectives of the President's Point IV program will be impossible of accomplishment.

Contract Rights Frequently Modified

Property and contract rights can be and frequently are modified by mutual agreement. The "pound of flesh" approach is not a proper solution to problems that have arisen due to a change in the basic conditions that were present at the time the contract was made. Neither is it a proper remedy for one of the parties unilaterally to disregard his solemn engagement. Where, with the passage of time and the appearance of unforeseen conditions, the carrying out of a contract strictly in accordance with its terms would create undue hardship, it is essential that both parties to the original contract likewise be parties to the changes. To maintain, as some do, that sovereignty includes the right to set aside such contracts unilaterally is not to exalt sovereignty but to put it in a class with minors who likewise are unable to make binding contracts. Nations that have come of age, like individuals who have attained their majority, recognize the practical value of their contractual powers.

If a sovereign is a party to a contract, it can make agreements covering

Wilson Endorses Competitive Research

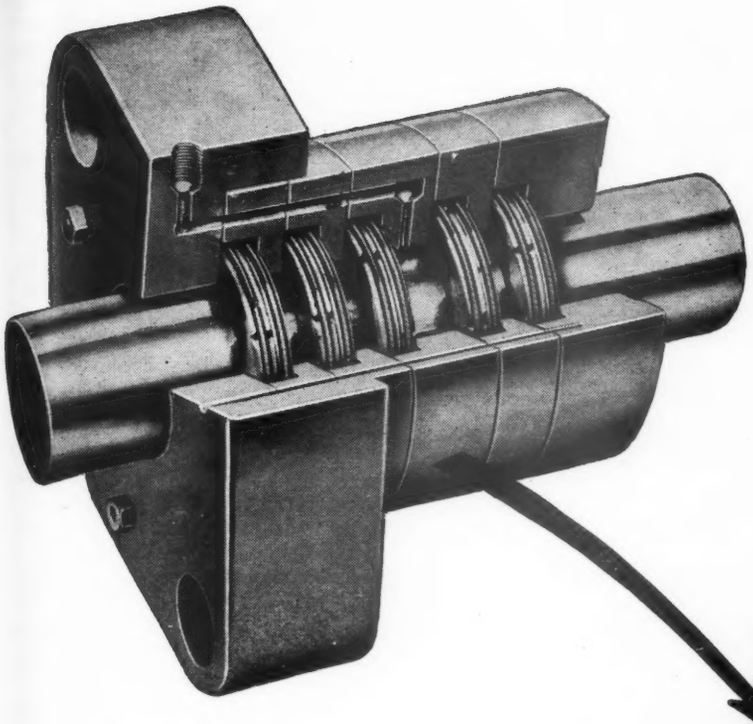
Competitive research in the past third of a century has raised the standard of living more than in any whole century of prior history, Dr. Robert E. Wilson, of Chicago, told the Institute of Petroleum in the Third Cadman Memorial Lecture in London, England recently.

Competitive research does a far better job than either cooperative or government research, although both government research and cooperative research by industry have real values in certain areas, the chairman of Standard Oil Company (Indiana) said.

Speaking on "Competitive and Cooperative Research in the American Petroleum Industry," he said there are a number of conditions that must be present if competitive research is to give the best results.

Among these conditions he asserted there must be a reasonable number of strong companies, able to attack problems aggressively from different viewpoints, as well as a sound patent system.

He pointed out, however, there are fields in which cooperative research has been found preferable, especially the work of the Cooperative Research Council, sponsored jointly by the automobile and petroleum industries. He also declared that API research "has repaid the industry—and so the public—many times what it cost."



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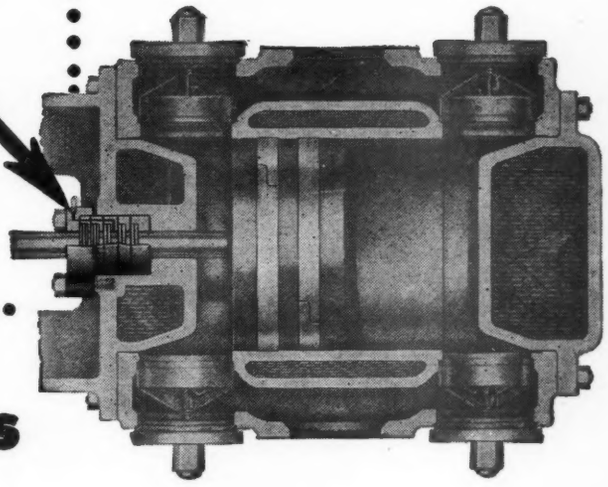

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This is why Cook full-floating all-metallic packings are used as the modern rod seal in so many newly developed compressors. Backed by over 60 years of specialized experience in the manufacture of piston rod seals, Cook packings are designed to function with a minimum of friction. They do this primarily by utilizing rings of proven anti-friction materials. These rings float in specially provided grooves which means that, even when rod vibration or misalignment develops, friction is not materially increased nor is the seal disturbed.

Be sure that your compressor comes equipped with this modern packing. Specify Cook by name when you order new equipment just to make sure.

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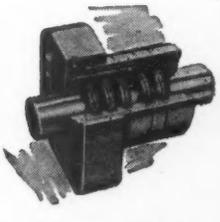

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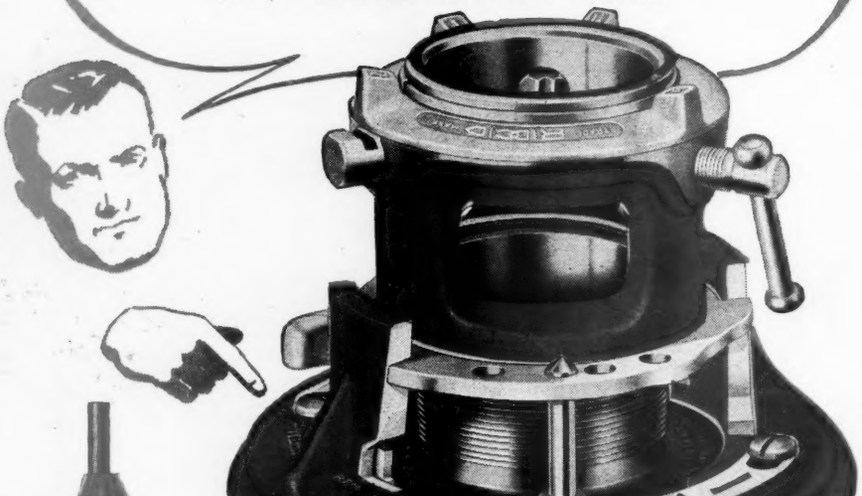

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vast interests within its own country. A typical example is the long term oil concession covering the exclusive right to extract oil throughout a country. Under such a contract situations may arise that are clearly contrary to the nation's welfare. Even so, emphasis always should be placed on a proper discharge of contractual obligations fairly entered into. When, however, conditions are so altered as to point to the need for contract modification, it should be undertaken in a friendly atmosphere with both parties seeking a just solution to their problems.

Gradually we have learned that in the case of long term contracts much can be done to guard against such substantial changes in conditions as might make enforcement throughout the contract period inequitable. In this country oil leases generally provide for royalty in kind. The royalty interest thus fluctuates with the value of the oil and more or less with the prosperity of the oil industry. Such contracts have proved reliable and equitable over their entire period.

Another type of arrangement that would seem to offer long term fairness and stability is the so-called 50/50 arrangement that seems to be the pattern now being adopted in some of the foreign concessions where the contract is with a government. Here again, subject to certain agreements with respect to determination of profits, the general objective is to provide that the government shall receive as compensation for its interest in the crude oil removed, half the profits earned by the company within the country. Payment may take different forms, including royalties and taxes, but it again reflects the welfare of the industry, with both parties to the contract, the government as well as the company, gaining or losing revenue with the ups and downs of profits in the industry.

Problems Can Be Settled By Negotiations

If it be admitted there may be occasions, though few, where contractual obligations should be changed, by what standards are the newer arrangements to be measured? I cannot supply the answer, but I am firmly convinced that most of the problems can be settled by bilateral negotiations provided both the parties to the contract are not only willing but determined to reach a fair conclusion. This is the pattern that has been followed in the past and is being followed now in respect to some of the concession areas. In undertaking such negotiations due regard should be paid both to past commitments and to existing circumstances. Should there be a complete failure to agree under these

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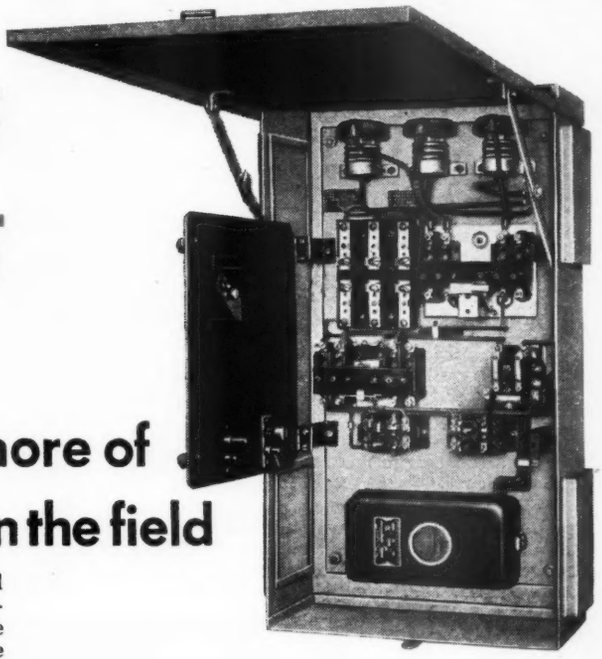

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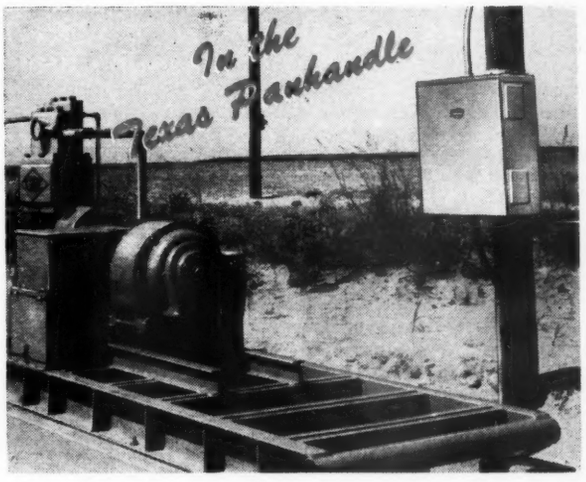
Oil Well Pumping Control has more of what you want than anything in the field

The Cutler-Hammer Oil Well Pumping Control is shaped by the special requirements of the oil country into the oilfield's outstanding well pumping control. It beats the heat. It beats the dust. It stands up in the toughest tests.

Aluminum painted enclosures beat back the sun's heat. Proper ventilation drains off the heat from inside. You don't have to prop the door open to dirt, insects and birds to keep this controller cool and working. Fine mesh screened, louvered and guarded ventilation, vertical dust-safe, dust-shedding contacts, neoprene gasketed dustproof timer enclosure, timer clock motor with excess torque—all these features keep the controller working in dustiest climates.

Unit type lightning arresters reveal condition at a glance. You don't have to rebuild controller if one blows. The Cutler-Hammer Controller with automatic timed restarting feature means the attendant doesn't have to reset the control after a power failure. He knows the C-H Controller will restart the motors on a safe staggered time sequence. When on-off pumping schedule is changed, the change is made simply by pulling accessible tabs, one pull for each 15-minute change—and no guessing. To reset a clock to correct time of day, attendant simply turns a handy palm size dial forward or backward. The wiring diagram with spare parts list and overload heater coil ratings is sealed in a dirt, grease, water and heat resisting plastic coat. You and your men will like these oil country starters better than any you've ever seen. CUTLER-HAMMER, Inc., 1459 St. Paul Avenue, Milwaukee 1, Wisconsin. *Associate:* Canadian Cutler-Hammer, Ltd., Toronto, Ontario.



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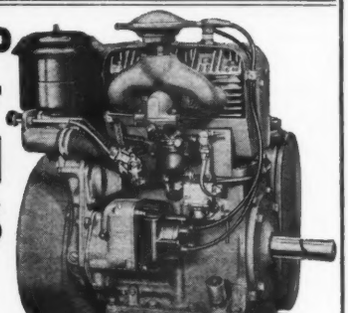

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1. Dependable air-cooling under all climatic and weather conditions.
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Piston Disp. cubic inches		45.9	53.9
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1400 rpm		7.2	8.6
2000 rpm		10	12
2600 rpm		11.2	13.3
Net weight in lbs., Standard engine, side-mount tank		220	220

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conditions — an eventuality hard to see—then I suppose some new authority is required to settle the matter between the parties. Certainly if we are ever to have a world governed by law rather than by force we must come to regard it as no more a limitation on a nation's sovereignty to be required to respect the contracts it has freely made, than we regard it as a limitation on an individual's freedom that he do likewise.

In the field of international relations, I believe the law has not grown to maturity. We are facing new problems and conditions for which rules of conduct have not been completely codified. The common law is a good illustration of a code of conduct under similar circumstances. As new situations arose, the law expanded to meet the problems but careful attention was paid to past relationships. Progress at times was painfully slow, but in the end the foundations on which our human societies were built were stable and the law did not become stultified.

Governments sometimes act under the name of nationalization in altering or setting aside their contracts. I think this is a failure to recognize true legal concepts. The right of a sovereign power to nationalize is one thing. The right of a sovereign power to make a contract binding on itself is another thing. To assert that the right of a sovereign to nationalize is superior to its right to make a binding contract is pure sophistry—the legal equivalent of an irresistible force meeting an immovable object. There are bound to be situations where the line between the two is rather hazy. But ultimately if we are to carry on commercial transactions between countries, contracts must be adhered to, and governments, as well as private individuals, must prove to be responsible parties.

The problem is a serious one. I doubt we know the answers today. It seems to me, however, that the requirements in this case are fairly clear. Unless some course of conduct can be found governing these contractual relationships I do not see how private capital can continue to be invested abroad. This would defeat our Point IV program and be contrary to much of the effort the Western nations are making to build military and industrial strength in friendly countries.

The greatest hope a small nation has for its own survival is that it can make valid and lasting agreements with large nations. A small nation that denies the sanctity of contracts is undermining the one principle of international conduct that says that the world shall not be ruled by force alone. * * *

SINCLAIR RESEARCH LABORATORIES—nine buildings containing the most modern testing equipment known—have contributed many of today's most important developments in petroleum products, production and refining. Under the Sinclair Plan, the available capacity of these great laboratories is being turned over to work on the promising ideas of independent inventors everywhere.

An Offer of Research Facilities to Inventive Americans Who Need Them

The Sinclair Plan is opening up the Company's great laboratories to every American who has an idea for a better petroleum product

INVENTIVE Americans are often at a loss today. Not because of any lack of ideas, but because of a need for expensive facilities to find out if and how their ideas work.

This was no obstacle in our earlier days. The Wright Brothers designed their first airplane with the help of a foot-square homemade "wind box"—and the plane flew.

In contrast, the man with a new idea in airplane design today often needs a supersonic wind tunnel costing millions.

In short, science and invention have become so complex that a man with an idea for a better product often needs the assistance of an army of specialists and millions worth of equipment to prove his idea has value.

Within the petroleum field, the Sinclair Plan now offers to provide that assistance.

Under this Plan, Sinclair is opening up its great research laboratories at Harvey, Illinois, to independent inventors who have sufficiently good ideas for better petroleum products or for new applications of petroleum products.

If you have an idea of this kind, you are invited to submit it to the Sinclair Research Laboratories, with the provision that each idea must first be protected, in your own interest, by a patent application, or a patent.

The inventor's idea remains his own property

If the directors of the laboratories select your idea for development, they will make, in most cases, a very simple arrangement with you: In return for the laboratories' investment of time, facilities, money and personnel, Sinclair will receive the privilege of using the idea for its own companies, free from royalties. This in no way hinders the inventor from selling his idea to any of the hundreds of other oil companies for whatever he can get. Under the Plan, Sinclair has *no control* over the inventor's sale of his idea to others, and has *no participation* in any of the inventor's profits through such dealings. Moreover, it is a competitive characteristic of the oil business that the new products adopted by one company are almost invariably adopted by the whole industry. This means that the very fact of his agreement with Sinclair should open up to the inventor commercial opportunities which might otherwise be hard to find.

How to proceed: Instructions on how to submit ideas under the Sinclair Plan are contained in an Inventor's Booklet available on request. Write to: W. M. Flowers, Executive Vice-President, Sinclair Research Laboratories, Inc., 630 Fifth Avenue, New York 20, N. Y. for your copy.

IMPORTANT: *Please do not send in any ideas until you have sent for and received the instructions.*

SINCLAIR—A Great Name in Oil

STRATEGIC OIL SUPPLIES†

GUSTAV EGLOFF*

Abstract

This paper outlines the strategic oil supplies of the world, which are located in two principal areas: The fields bordering the Gulf of Mexico and the Caribbean Sea; and the fields in the Middle East, where petroleum is obtained from the desert countries of Iran, Iraq, Saudi Arabia, and Kuwait. It also outlines the world's refining situation. Its purpose is to point out the strategic importance of the prolific sources of oil in the Middle East and their effect on the fueling of a long war, and what it would mean to the countries of the West if this enormous supply should be cut off by Russia or her satellites. "Adequate protection of this area now may well slow down or stop the Russian time table for aggression."

Two Great Oil Areas

The strategic oil supplies of the world are situated in two principal areas, viz.: The fields bordering the Gulf of Mexico and the Caribbean Sea, and the fields in the Middle East. The total world production of crude oil is about 10,500,000 bbl a day, of which the United States produces about 52 per cent, the Middle East 17 per cent, Venezuela 14.5 per cent, and Russia and her satellites only 8 per cent. The combined production of the largest producing areas, viz., the United States, Venezuela, and the Middle East, accounts for almost 85 per cent of current world output. Table 1 summarizes the current production of petroleum by world areas.

Russia's Predicament

To compensate for their lack of petroleum supplies, Russia and her satellite countries use the expensive processes of coal hydrogenation and oil-shale retorting to produce additional supplies of oil. It is difficult to determine just how much oil is produced from these processes. In eastern Germany current plans call for the production of 20,000 bbl a day of automotive fuels by the hydrogenation of lignite. In Czechoslovakia a coal-hydrogenation plant is available for producing 30,000 bbl of gasoline a day. It seems reasonable to estimate that at least 100,000 bbl a day of synthetic liquid fuels from coal and oil shale are being produced in Russia and satellite countries. The combined total of crude oil and synthetic oils probably amounts to about one million barrels a day, which is less than 10 per cent of total world production.

TABLE 1. World crude-oil production July, 1950

(Thousands of barrels per day)

Western Hemisphere		
United States	5,504.0	
Venezuela	1,533.3	
Mexico	195.2	
Other	353.2	
	7,585.7	71.8 per cent
Western Europe		
Germany	21.9	
Netherlands	14.4	
Other	5.1	
	41.4	0.39 per cent
Russia and Eastern Europe		
Russia	730.0	
Roumania	85.0	
Austria	25.0	
Other	23.6	
	863.6	8.15 per cent
Middle East		
Iran	691.2	
Iraq	128.5	
Kuwait	363.7	
Saudi Arabia	558.6	
Egypt	39.9	
Other	66.3	
	1,848.2	17.5 per cent
Other Asia		
Indonesia	130.0	
British Borneo	82.0	
Other	23.1	
	235.1	2.2 per cent
World total	10,574.0	

TABLE 2. Cumulative crude-oil production through 1949.

(Thousands of barrels)

World	61,737,998
United States	38,939,286
Venezuela	5,000,000
USSR	6,292,473
Total Europe	8,045,208
Middle East	3,371,677

Most Challenging

Of all producing areas, the Middle East is by far the most challenging in the world at the present time. It includes the countries of Iraq, Iran, Saudi Arabia, Kuwait, and Bahrein, and has a land area equal to 67 per cent of that of the United States. Control of the Middle East fields is now entirely vested in western democratic nations; 47 per cent is held by the British, 41 per cent by Americans, 6 per cent by the French, and 6 per cent by the Dutch. Most of the know-how for exploration and well drilling has been supplied by American and British operators who gained their experience in the oil fields of the United States and other countries in the Western Hemisphere. They have developed this area at great cost and considerable financial risk. Native labor was entirely uneducated for the kinds of jobs necessary to oil production and refining. In addition to this task of training labor, a large number of employees had to be transported from the United States and western Europe. Whole new towns had to be built with living quarters, sewage and water systems, schools, and recreation facilities to make these areas habitable. Oil companies of the United States, Britain, France, and Holland have invested superhuman effort in these Middle East fields, and have every right to the oil therefrom.

Middle East oil production is remarkable in many ways. The production per well averages over 5,000 bbl a day in all the Middle East fields; and some wells yield as high as 15,000 bbl a day. At present there are only about 300 producing wells. In the United States, by contrast, there are about 450,000 producing wells averaging about 12 bbl a day, although there are much higher producers in some fields. The average production per well for the whole world is about 20 bbl a day.

Oil production is backed by enor-

†Presented before a Lubrication Group Session, under the auspices of the Division of Marketing, during the 30th Annual Meeting of the American Petroleum Institute, in the Biltmore Hotel, Los Angeles, California, November 14, 1950.

*Universal Oil Products Company, Chicago, Illinois.

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mous reserves. The areas of greatest reserves, however, do not always correspond to the areas of largest current production. The greatest development has occurred in the United States, where almost a million oil wells have been drilled since the beginning of the industry in 1859. Table 2 shows the accumulated production of petroleum in various world areas since the industry began.

U. S. Commanding Position

The data show that the United States has produced 63.7 per cent of all the oil that has been brought above the ground. Despite the fact that the higher producing rate in the United States would be expected to leave relatively small amounts of oil for the future, the proved reserves have increased throughout the years so that approximately the same ratio of reserves to production has been maintained. Data for 5-year intervals since 1920 are given in Table 3.

Estimated Future Reserves

Many geologists have estimated the ultimate amount of oil that will be discovered in the world's sedimentary rock formations. With increasing knowledge of earth formations and the types of structures in which oil is most likely to be found, the estimated reserves have steadily increased over the years. Some geologists believe that 1,500 billion barrels more of petroleum will eventually be obtained from the earth's oil-bearing rocks. The amount that will be recovered from formations under land areas is estimated to be between 500 billion and 600 billion barrels, approximately 10 times the cumulative world production to date. Reserves of 1,000 billion barrels are estimated to be under the continental shelves.

As to the distribution of the oil reserves, the geologists calculate that, of those under the land areas, about 150 billion barrels are yet to be discovered in the Western Hemisphere and 350 billion in the Eastern Hemisphere. The most commonly accepted figure for the United States at this time is 100 billion barrels. Table 4 indicates the probable resources.

No Foreseeable Shortage

Of the ultimate resources estimated in Table 4, it appears that about 25 per cent are in the Russian zone of domination and 75 per cent under the control of the western democratic nations. The estimates are based on known oil-bearing formations. Past experience has shown that oil is also discovered in unpredictable areas, and it is safe to assume that much greater quantities will be found than are predicted at present. Even though they are not, the estimated reserves will supply oil for 500 years at the present rate of consumption. According to these data, there is no foreseeable oil shortage.

Refinery Location

In any emergency the location and capacity of refineries are of almost greater importance than production and reserves. Total world refinery capacity is about 11,600,000 bbl daily, of which 6,700,000 bbl are located in the United States. Next in capacity are the refineries of Latin America that can process about 1,500,000 bbl daily—1,000,000 bbl of which uses Venezuelan crude in refineries at Curacao, Aruba, and Venezuela. The Middle East has the world's largest refinery at Abadan, Iran, where more than 500,000 bbl of crude oil are charged daily. Other large refineries in the Middle East are the one on Bahrein Island, which charges 150,000 bbl a day, and the one at Ras Tanura, which charges 140,000 bbl. The products of the Middle Eastern refineries are practically all shipped to western European countries because local demands are almost zero.

TABLE 3. Estimated proved reserves of crude oil, natural-gas liquids, and total liquid hydrocarbons in the United States, by years.
(Thousands of barrels)

Year	Production during year	Proved reserves end of year	Ratio of reserves to years production
1920	442,929	7,200,000	16.3
1925	763,743	8,500,000	11.1
1930	898,011	13,600,000	15.1
1935	996,596	12,400,000	12.4
1940	1,351,847	19,024,515	14.1
1945	1,736,717	20,826,813	12.0
1949	1,996,669	28,586,000	14.3

TABLE 4. Land-area oil reserves.

Country or Region	Estimated resources: Billions of barrels	Estimated resources: Per cent
United States	100	16.7
Venezuela-Colombia-Mexico	45	7.5
Other	65	10.8
Western Hemisphere (total)	210	35.0
Russia-Siberia	150	25.0
Middle East	150	25.0
Oceania (East Indian archipelago)	35	5.8
Other	55	9.2
Eastern Hemisphere (total)	390	65.0
World (total)	600	100

TABLE 5. ECA recommendations for increasing European refining capacity.
(Barrels per day)

	End of 1949	1952-53
Austria	7,800*	12,400
Benelux	7,000	165,000
Denmark	600	16,000
France	250,000	375,000
Greece	....	8,000
Italy	63,000	146,600
Norway	700	700
Portugal	6,000*	9,200
Sweden	11,500	41,000
United Kingdom	135,000	390,000
West Germany	38,000	94,400
	519,600	1,258,300

* 1948

The refineries in western Europe, which operate mainly on imported crude, are being enlarged under ECA sponsorship, so that by 1952-53 they may be able to supply domestic demands for petroleum products. Table 5 shows refinery capacities in these countries at the end of 1949, and the projected increases in throughput.

Table 5 shows that, in the next 2 or 3 years, the capacity of western European refineries will be increased by 738,000 bbl per day.

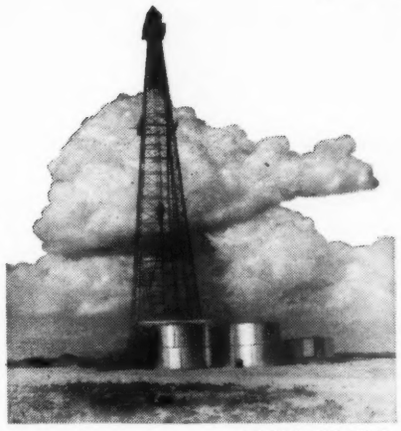
Russian Facilities Inadequate

The throughput of Russian refineries at the end of 1949 was 680,000 bbl of crude oil a day. More than 100,000 bbl of oil were charged to refineries in Russian-dominated countries. Including synthetic oils from coal hydrogenation and oil-shale retorting, it seems probable that Russia and her satellites are refining around 1,000,000 bbl a day of crude petroleum and synthetic oils. Russia is not a highly industrialized country, and reportedly has 1,250,000 motor vehicles of all types—so that production for peacetime transportation is ap-

Statistician's Place in Industry Assured

The statistician has proved his importance in the British industry and his future promises even greater appreciation for the role he plays, is the conclusion drawn by W. J. Harrison, statistician Anglo-Iranian Oil Company, Ltd. Harrison is author of the paper "The Use of Statistics as an Aid to Management in the Petroleum Industry," which was presented before the Third World Congress held at The Hague recently.

The paper listed three types of statistical activity required in British industry: The recording in numerical form of the company's activities; the provision of an economic background to give perspective to the firm's activities; and the mathematical analysis of certain data in order to elucidate information. Each aspect of statistical operations is discussed at length, and the contribution of each to managerial policy analyzed in the paper.



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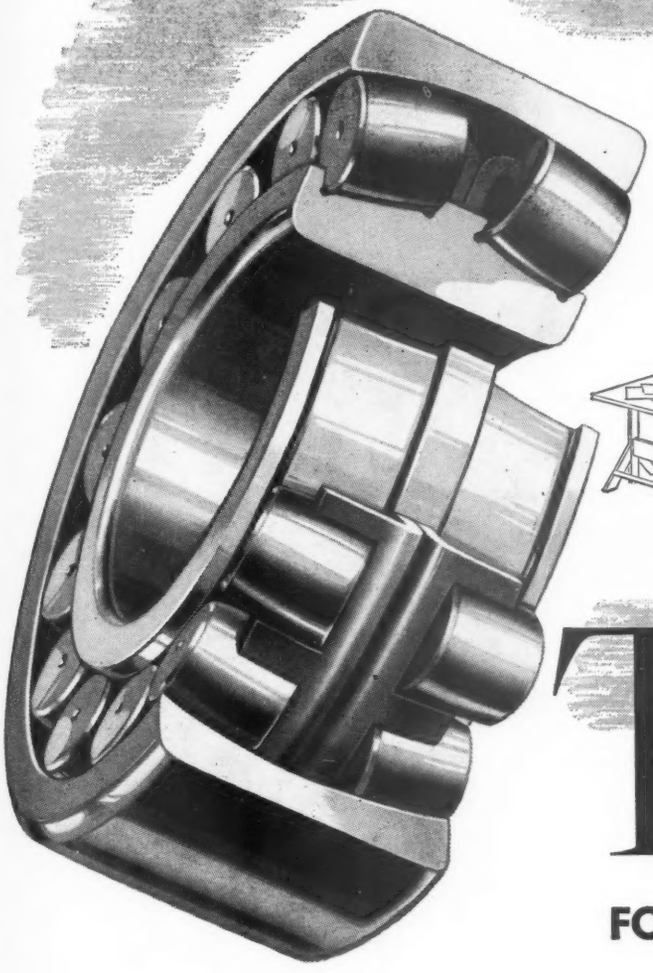

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parently sufficient. In the event of an emergency, however, its oil production and refining facilities would be inadequate.

U. S. World Position

The data given heretofore will be compared to show the distribution of oil supplies in case of a showdown between democratic and totalitarian countries. The democratic nations that have developed the world's oil fields on their own initiative to their present high capacity are in control of about 90 per cent of present-day production and about 75 per cent of the estimated oil reserves. The United States has a production of 5,800,000 bbl of petroleum a day at present, with another million barrels shut in but available when needed. It also has access to Canadian and Mexican oil without having to rely on transportation by sea. Nearby are Venezuela and other South American oil-producing nations. We probably can depend on the Venezuela supply in any emergency, although the threat of submarine attack cannot be discounted. It is evident that the United States has more than ample oil for civilian needs and high military demands. In a long large-scale war, fought thousands of miles away, however, it would be difficult to supply all requirements if our allies were entirely dependent on us for oil.

USSR World Position

In any long conflict Russia would have to get more oil, and the Middle East stands as the most obvious point to seize because of its proximity. Control would not only divert supplies to Russia and triple her available resources, but also would cut off this source of oil from western European countries, leaving them more prone to invasion. Russia is reported to be fomenting border incidents and tribal wars in Iran with the evident aim of developing a weak spot that will be ripe for invasion.

Middle East Transportation

The availability of Middle East oil to western Europe in both peace and war is dependent on transportation. Even though control of the Middle East fields remained in friendly hands, western Europe would be cut off from this supply if transportation were disrupted. Heretofore the oil has been carried entirely by tankers for 3650 miles around the Arabian peninsula through the Suez Canal, but a 1000-mile pipe line has recently been completed that will carry as much as 500,000 bbl per day directly to the Mediterranean. In case of war the pipe line is vulnerable to air attack, but tanker transport is subject to the usual hazards of maritime transportation and the vulnerability of the Suez Canal to air attack. The pipe line is of greatest importance in an emergency because it opens a second route of supply. The pipe line also has the advantages of offering much cheaper and faster transportation.

Another point that should be considered is the vulnerability to attack of the large Middle Eastern refineries and storage tanks. In the event of war every attempt would be made by the opposite side to attack these sources, regardless of who had control over them.

Russia, however, is much less likely to start a war if she does not have this prolific source of oil. By maintaining control in the hands of the democratic countries, the tide may eventually be turned against communistic expansion and peace maintained throughout the world. The western powers must make it clear that they will resist to the limit any effort to wrest control of the Middle East oil from the democratic nations that have developed these resources for the benefit of mankind. Adequate protection of this area *now* may well slow down or stop the Russian time table for aggression. * * *

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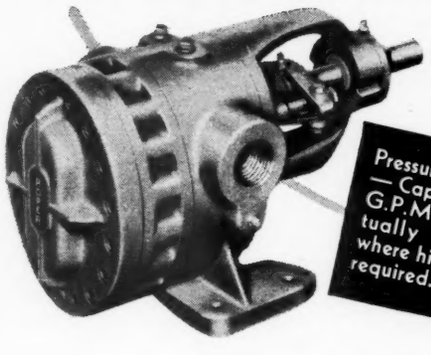

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